Development of a Prototype Computer-Assisted Well Control System for Deep Ocean Drilling with Automated Detection of Underground Blowouts

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Table of Contents

Chapter 1

Executive Summary

This LSU study was funded by the Minerals Management Services U. S. Department of the Interior, Washington, D.C., under Contract Number 14-35-001-30749. This report has not been reviewed by the Minerals Management Service, nor has it been approved for publication.. Approval, when given does not signify that the contents necessarily reflect the views and policy of the Service, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

The goal of this project was to improve rig safety by reducing the potential for surface and underground blowouts through providing enhanced bottom hole and casing seat pressure control during the well kill process. As a means to reach this goal, an advanced prototype computer-assisted well control system for deep-water operations was developed that can also be used on surface or land rigs. This system, which uses process control technology, can achieve as much as a tenfold reduction in bottom hole pressure (BHP) variances during well control operations and has the advantage of freeing the rig crew to monitor the overall well control operation more closely. Additionally, a real-time, automated means for detecting underground blowouts was successfully tested during well kill operations. This detection system, which was incorporated into the computer-assisted well control system, uses existing technology.

The prototype system was demonstrated to industry and to MMS during an annual workshop held at LSU. An international service company is currently evaluating the commercial use of the prototype technology with one of their drilling choke product lines.

Chapter 2

Introduction

The Minerals Management Service is concerned about reducing the potential for surface and underground blowouts because Congress has mandated that MMS is responsible for worker safety and environmental protection.

Deep water offshore locations are considered to be some of the most promising ones remaining to be explored for hydrocarbons. Several companies have made significant deep-water discoveries that have generated great interest in this type of exploration. However, deep-water exploration is expensive, and well control planning for these sites is also very expensive, as well as difficult. Despite the increased sophistication and corresponding expense of deep-water well design technology, kicks (unintentional flow of formation fluids into the wellbore) still occur, and the subsequent complications that arise following kicks must be properly handled. When kicks occur, well control procedures (often referred to as well kill operations) must be implemented to regain full control of the well. Proper control of the well during well kill operations is essential to preventing either a surface or underground blowout. The risk of underground blowouts is especially great because of the tendency for formation fracture to occur at much lower equivalent mud densities than in shallow water locations. This project is, therefore, focused upon proper well control for deep water drilling operations.

Problem identification

Once a kick has occurred and the well has been shut-in, the task at hand is the proper analysis of the situation and selection of the proper well control action to be taken. The type of well kill technique selected is determined by the amount of open hole, blowout preventer (BOP) stack arrangement and pressure rating, surface gas handling equipment, kick size and fluid type, the presence of hydrogen sulfide, shoe fracture gradient, integrity and location of the drill string, fluid mixing capacity, and weight-up material on hand. However, most of these considerations are already known when the kick is initially taken, leaving only the planning and execution of the well kill program to the rig crew.

The deep water rig crew's well control skills are even more critical than those needed on surface or land rigs because of the complexity of the well, the type kick fluid(s) encountered (typically high pressured natural gas), the reduction in fracture gradients for a given penetration depth, and the potential for lost circulation. First, the long choke line associated with deep water wells makes controlling (i.e., holding constant) the bottom hole pressure (BHP) almost impossible for most rig crews during a well kill operation. Second, highly charged/pressured natural gas is the prevalent kick fluid for deep water locations, increasing the risk of a blowout. Third, the fracture gradients associated with equivalent penetration depth into the seafloor sediments are greatly reduced, increasing the risk of lost circulation with secondary kicks and underground flow or an underground blowout. Furthermore, other complications during the well control process are more likely to arise for the deep water wells. Complications in the well kill process often arise due to poor operator judgment or coordination skills and are typically preceded by secondary kicks and lost circulation, both of which are avoidable most of the time if the well is shut-in in a timely fashion and a well kill procedure is properly executed.

Problems reported in deep water well control events suggest that the rig crews are sometimes ill-prepared or -trained to determine the proper response to a well control situation and to effectively implement the well kill plan chosen. Misdiagnoses of the problem, errors in calculating a well kill plan, failure to control pressures during the pump out cycle of the well kill process, and, in general, poor execution of the well kill plan are a few of the specific problems encountered. Also the difficulty of controlling BHP during well kill operations is compounded by the fact that the fluid pump and drilling choke are manually controlled by two individuals, typically the driller and company representative or toolpusher. These crew members must work in concert if the well kill program is to be effectively implemented, yet they may never have killed a well or even trained together as a team because of the infrequency of well control operations. Finally, the inability of the crew to properly control pressures during the well kill operation makes downhole problem recognition, e.g., lost circulation and underground flow, very difficult. In fact, it is human error factor that makes this research, and its eventual implementation, imperative.

Objectives

The goal of the research reported herein was to develop a computer-assisted well control system for deep water drilling operations that would address the problems associated with deep water wells such as underground blowouts. Incorporation of this type of technology would enhance the rig crew's performance by freeing the crew to monitor the overall well control operation more closely. Accomplishment of this goal was achieved through more precise control of BHP, resulting in a reduced potential for surface and underground blowouts.

The scope of this research was limited to system development for handling shut-in well control situations that require implementation of one of the constant BHP well control techniques. In general, either the wait-and-weight method or the driller's method is typically used for well control; these two methods are the particular techniques considered specific to this work. Specialized well control procedures such as bullheading, etc., were not within the scope of this effort. Additionally, to further limit the scope of this project, the wellbore configuration was limited to vertical wells[1].

The specific research objectives were:

1. To develop a prototype computer-assisted drilling well control system;
2. To test the system utilizing field drilling equipment and actual test wells; and
3. To compare the computer-assisted well control test results with well control results produced by operators manually executing similar well control procedures on the same wells.

The prototype computer-assisted well control system was tailored to meet the challenges of deep ocean drilling environments, providing both assistance in the routine calculations required for a well kill plan and process control of the deep water well control procedure, including fluid pump and drilling choke

[1] The system as designed could apply the driller's method to not only vertical wells but also highly deviated or horizontal wells. However for simplicity of first design, vertical wells were the focus of this study.

control. Additionally, the system included basic systems analysis logic for identifying signs of lost circulation and underground flow that may occur during the well kill procedure. The system was not intended to provide complete expert systems analysis[2] of possible problems, but only to demonstrate how this type logic, when applied to real time, could prove beneficial during a well kill program.

Methodology

To meet the stated objectives, the development and implementation of a prototype computer-assisted deep water well control system required that four elements be completed. First, the accuracy of input or surface pressure data was to be validated, i.e., the gauge reading had to reflect the true pressures being experienced by the wellbore, and the most accurate means of acquiring pre-kick and post-kick pressure data had to be determined. Second, computer software was to be developed that would generate a well kill plan utilizing the input data and outputting the results in a format readily available for use by the computer in the well kill process. Third, a computer-assisted process control system was to be developed that would be capable of real-time data monitoring, fluid pump and drilling choke control, and process control of the well kill operation. Finally, the system had to incorporate expert systems logic and demonstrate capability of real time detection and identification of anomalies that occur during a well kill procedure such that deviations from the well kill plan could be detected and possible causes acknowledged. Again, the purpose of this part of the study was to show that the system is robust enough to demonstrate the benefits of this type of technology and was not intended to provide an exhaustive problems identification and analysis expert system.

Scope

The prototype system developed is intended to demonstrate to the petroleum industry that current technology exists that is capable of enhancing deep water well control safety. This was achieved by providing equivalent or better pressure control than typically can be provided by the rig crew. Due to limitations of measurement-while-drilling technology in a low flow mode, as is found during well control operations, all modeling was based on surface pressures and data typically available on the rig. All the data brought into the computer system in real-time is the same as is available to the rig crew. Normally available field equipment, such as high pressure fluid pumps, drilling chokes, pre-charge pumps, pit-level sensors, was used during the development and testing of the system.

Modeling solely based on the data found at the rig site was deliberate and is considered to be an important factor to convince the rig crew to accept a system of this type. If engineers and physicists are the only ones capable of deciphering the required data inputs, then the rig crew will not accept or even give the system a chance. In this scenario, the concept of automated well control would be lost due to over-sophistication.

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[2] TRACOR Incorporated has recently completed a multi-year, $1.5 million, expert systems analysis project for this very application but not designed to operate as a real time system. A system of the type that TRACOR developed is well beyond the scope of this research. However, we have worked together with Tracor in testing their expert system using the LSU/MMS research well facility.

Program development

Completion of the four tasks listed in Section 1.3 was accomplished in four separate phases. In Phase 1, field equipment (gauge protectors, hydraulic instrument hoses, hydraulic gauges and electronic pressure sensors) was taken to the laboratory and analyzed to identify potential sources of well control input data errors. The following section (Section 2) on data validation documents: 1) the scope of the research task, 2) the methodology for accomplishing the tasks of this phase, 3) the laboratory test apparatus, and 4) the results and conclusions reached as a result of this effort.

Phase 2, the development of a computer-assisted well kill plan (or kill sheet), was built on data proven valid in Phase 1. In Phase 2, a computer-assisted method for obtaining the pre-kick slow circulation rate pressure data was developed, data files for storing pertinent well data was established, and software for computer generation of a well kill plan was developed. The developmental work and end product for Phase 2 of this research is fully described in Sections 3.3.2 and 3.3.3 of this report.

Phase 3, the development of the computer-assisted deep water well control system, is detailed in Section 3.3.3. The methodology used to develop the system, test procedures and test facility used in validating the system, the test results, and conclusions are documented.

The last phase, Phase 4, of this research is documented in Chapter 4. During this phase, rule based software for problems recognition and identification was developed. This work keyed on lost circulation and underground flow with testing on a live research well at Louisiana State University Petroleum Engineering Research and Technology Transfer Laboratory (PERTTL). Again, the methodology, testing and results are systematically documented.

Finally, Chapter 5 brings together all the results and conclusions obtained in meeting the overall research goal: the development of a computer-assisted well control system for deep water drilling.

Chapter 3

Validity of Input Data

Industry experience with problems resulting from data input sensors has shown that the most serious problems have resulted from problems with gauge protectors used to isolate the gauges from drilling fluid.

The amount and quality of available information is key to any well control operation. Certain data required for a well kill procedure cannot be quickly obtained once a kick occurs. Typically, two types of data are routinely collected and stored for use prior to encountering a well control problem. The first type is the drilling and well data, normally contained in the morning driller's report that provides facts relative to the current status of the wellbore and operations. This information is critical for processing hole volumes, pump factors, and pressure schedules, and includes true vertical depth, measured depth, casing types and setting depths, drillstring pipe types and lengths, mud type and density, bottom hole assembly information, bit size, and leak-off test pressure.

The second type of pre-kick data needed is the drilling fluid frictional loss information, which is required for start-up schedules and benchmark pressures at slow circulation rates. These data are essential for helping identify problems encountered during a well kill operation. Since drillstring friction increases with depth, this information is currently updated or collected manually (i.e., by physically observing pressure gauges while circulating) once a tour or shift when drilling is in progress. This information is also collected after cementing casing but prior to drilling out, and after the drilling fluid type or density has been changed. Frictional pressure losses are determined for two, sometimes three, different flow rates in order to give the rig crew a range of circulation rate options that can be used to circulate the kick fluids from the well.

Post-kick information is one other required set of data for developing a well kill plan or kill sheet. These data consist of stabilized shut-in drillpipe and casing pressures and pit gain. The pit gain is typically taken from the Pit-Volume-Totalizer system, and verified visually by the mud man at the fluid tanks. The shut-in pressures are typically taken from analog hydraulic gauges. To date, the analog gauges are the dominant means of determining pressures; however, electronic gauges or displays are beginning to show up on the rig floor[3].

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[3] Electronic pressure sensors must be an integral part of the rig's pressure monitoring and data acquisition system if a real-time computer-assisted system is to be implemented..

Concern Regarding Accuracy of Gauge Readings

Given that electronic sensors have only recently made their debut in the oilfield as part of the well control equipment, the question of sensor accuracy must be addressed. Understanding how a sensor's accuracy can be compromised at installation also needs to be discussed.

The linearity and accuracy of the electronic sensors have been well documented and published by the service companies that offer this type of data collection service. Two U.S. companies that offer this type of sensor report the accuracy as 0.25% of full scale. (Note that the accuracy is not reported relative to a gauge reading). That means that a 0 to 5000 psig sensor is accurate to ±12.5 psi of actual pressure. Obviously, a 0 to 10,000 psig sensor is accurate to ±25 psi of actual pressure and a 0 to 15,000 psig sensor is accurate to ±37.5 psi. This is in contrast to current visual data being collected from analog gauges that vary up to 150 psi from actual pressure and which typically show 100 psig on the gauge when no pressure is on the system. This leads to the question of whether the location for installing electronic sensors makes a significant difference in accuracy of the sensor reading. If electronic sensors are installed directly to the pressure source, the stated accuracy will be realized. But what about attaching the sensors to the existing hydraulic analog gauge system, say behind the pressure gauge on the remote choke panel as is often done? Does any component of the existing hydraulic analog system add error to the readings? Additionally, if taking visual shut-in pressure readings from the hydraulic analog pressure gauge system, how accurate are the readings? All these questions must be answered to understand the full range of benefits to be derived from a computer-assisted system. However, to know the potential benefits of the new system, one must have an understanding of the current system.

Remote pressure measurement for the current hydraulic pressure measurement system refers to a system wherein a pressure source communicates with its indicator gauge or sensor by means of a hydraulic fluid link. **Figure 1** depicts the type of system that is currently used. It has four basic components: (1) pressure source; (2) gauge protector; (3) transfer fluid link; and (4) gauge element. Gauge protectors are usually installed on the standpipe, choke, and pump manifolds. The pressure within any one of these manifolds will, henceforth, be referred to as the process pressure. The gauge protector prevents the mixing of process fluid (drilling mud, gas, salt water) with the clean transfer fluid (instrument oil), which contacts the gauge element. The interface between these two fluids is maintained by either a flexible diaphragm or a so-called free-floating piston. A 50-foot length of high pressure hydraulic hose is the normal transfer fluid link, but 1/8-inch stainless steel tubing is sometimes used. The gauge element can be either analog or digital and is located on or near the rig floor, for example on the driller's console or the choke control panel. The typical pressure gauge is a single coil, Bourdon-tube with a full scale limit of 10,000 or 15,000 psig.

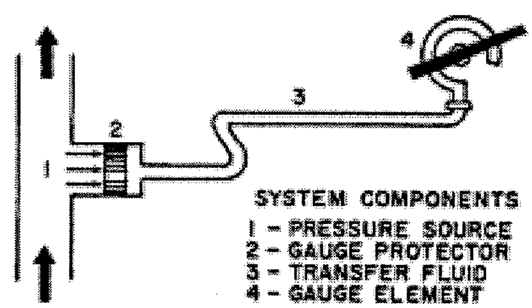

Figure 1: Basic components of a remotely-sensed, pressure measurement system.

Errors in the remote measurement of drillpipe and casing pressures via the hydraulic pressure measurement system have been known to cause serious problems during well control operations. Drilling personnel attending the LSU Well Control School relate experiences of pressure measurement errors that vary from 100 to sometimes several thousand psi. A gauge which reads correctly below a certain pressure level but goes blind above this level is a common problem. Similar errors (which have since been duplicated in the laboratory using standard oil field equipment) have been noticed occasionally at the LSU PERTTL Facility. Therefore, this phase of the research was deemed necessary to ensure the validity of data obtained from electronic sensors attached to pre-existing hydraulic remote measurement systems.

Phase 1: Objective

Phase 1 of this research involved identification and quantification of the sources of errors in the hydraulic remote pressure measurement system. If correction of errors was deemed necessary, a methodology was to be developed by which corrections for similar rig systems could be made.

Methodology

Experience gained from the training well had shown that a pressure measurement system, as previously defined, could have two blind regions. As illustrated by the analog display in **Figure 2**, a lower dead band (LDB) exists where the pressure gauge does not follow low-range excursions of process pressure. Instead, the gauge will indicate some constant minimum value denoted as P1. Similarly, in the upper dead band (UDB), the gauge indication will never exceed some constant value denoted as P2, even when the process pressure is much higher than this value. In essence, for process pressures lower than P1 or higher than P2, the pressure measurement system malfunctions. Gauge indications larger than P1 (yet less than P2), when used in conjunction with suitable correction factors, could provide true measures of process pressures. A determination had to be made as to whether these LDB and UDB pressure errors are specific to the analog gauges or to the systems to which the electronic sensors are to be attached.

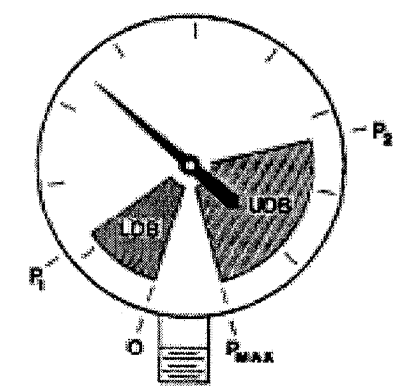

Figure 2: Usable Range of Gauge Indications (P_1 to P_2) Resulting from Dead Band Regions (LDB, UDB) Imposed by System Constraints.

These pressure response limits were thought to be caused by the interaction of the individual components of the system. Remote pressure measurement depends upon pressure in the process fluid being transferred through the gauge protector to the instrument oil in the hydraulic hose and, thence, to the gauge element. Consider the case of a hydraulic hose having a significant compressibility. With an increase in pressure in the instrument oil, the hose would balloon or expand, thereby increasing its internal volume. Consequently, a sizable pressure increase at the gauge element might require that a significant volume of oil be added to the hose. (Then, too, as the oil itself is slightly compressible, it would tend to decrease in volume, requiring that still more oil be added to the hose.) This additional oil must come from within the gauge protector. As the gauge protector can supply only a finite volume of oil, there would definitely be an upper limit on the maximum pressure that could be maintained inside the hose (and consequently at the pressure gauge). This could well be the cause for the upper limit of pressure response in a particular system, denoted previously as P2 in Figure 2.

Since a pressure increase in the transfer fluid link requires the expulsion of some (if not all) of the oil from the gauge protector, its floating piston or elastomer diaphragm would shift or deform significantly. In the case of a diaphragm-type protector, this stretching of the elastomer might cause a discernible pressure difference across the diaphragm. Hence, the process pressure could possibly be greater than the system (oil) pressure. This could explain, in addition to any errors in the gauge response itself, why pressure readings within the limits imposed by the lower and upper dead bands could still require correction factors before they are truly indicative of process pressures.

The foregoing analysis suggested that laboratory tests be designed to provide measurements of:

1. the volume of working fluid contained in each type of gauge protector;
2. pressure loss incurred while expanding the elastomer diaphragm, or pressure loss caused by any sliding friction in a piston-type protector;
3. additional fluid volume and diaphragm distortion as a consequence of pre-charging the system to an elevated pressure (while the process side is at atmospheric pressure);
4. isothermal compressibility of the oil-filled hydraulic hose (or steel tubing), in terms of oil volume additions required to realize specific internal pressures;
5. isothermal compressibility of an oil-filled Bourdon tube gauge;
6. the isobaric thermal expansion coefficient of the instrument oil; and
7. the effects of elevated temperature on the response of a total system.

Laboratory Test Apparatus

Figure 3 is a schematic of the laboratory test model used for data collection and results verification. A positive displacement mercury metering pump was used as the pressure source while the gauge protector, hydraulic hose and gauge element were standard oil-field equipment. Pressures upstream of the gauge protector were measured by a Heise gauge, 0 to 10,000 psig span. All pressure measurements between 0 and 5000 psig were corroborated by measurements made with 4-20 mA pressure transducers, which could also monitor the discharge pressure of the protector. Fluid flow to and from the gauge protector was metered with the calibrated injection pump and verified by volumetric measurements.

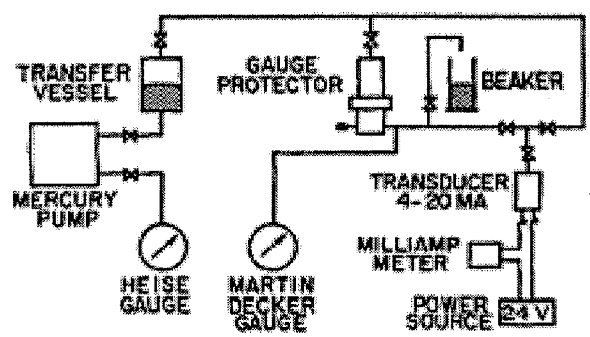

Figure 3: System Schematic of the Pressure Measurement Model.

All pressure measuring equipment was calibrated using a dead weight standard, known to be accurate to ±0.03%. The pressure transducers tested accurate within ±0.2% of the indicated value, while the Heise gauge tested to be within 0 to -10 psi. Transducers with range of 1,000 and 5,000 psig were used interchangeably to minimize reading error, depending on the pressure range of a test. Only the Heise gauge was used for pressure measurements above 5,000 psig. A composite compressibility was determined for the complete pressurization system on the process side of the gauge protector. Test results were factored appropriately such that they would not be biased by the compressibility of the mercury pump system, the transfer vessel, and its associated oil-filled tubing.

Findings and Results

Each component of the remote pressure measurement system was independently evaluated. Then all were combined and tested as a complete measurement system, with the effects of elevated temperature also documented. The resulting data were then codified in the form of graphs and tables to simplify use. All graphs and tables given in this text are specific to the equipment tested and are not intended to be used indiscriminately.

Gauge Protector

The gauge protector notably acts as a barrier device, separating the process fluid from the transfer fluid (instrument oil). It also provides a reservoir of instrument oil for the pressurization of the oil-filled transfer link. The total volume of oil that can be expelled from a gauge protector reservoir into the link was defined as the working fluid volume. As explained previously, there are two types of gauge protectors. One type uses an elastomer diaphragm to separate the process fluid from the instrument oil, as shown in **Figure 4**, while the other type replaces the diaphragm with a floating piston. Evaluation of gauge protectors involved defining: (a) the working fluid volume for both the elastomer and piston units; (b) pressure losses due to expansion of the diaphragm; (c) pressure losses incurred across the piston caused by sliding or static friction; and (d) the effects of precharge. These volumes represent the total fluid available for pressure transmission.

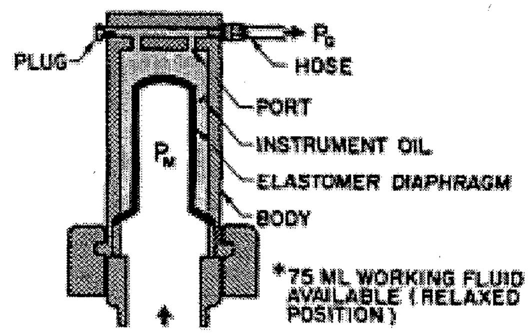

Figure 4: Sectional View of a Typical Diaphram-type Gauge Protector, where P_M is the Process Pressure and P_G is the pressure sensed by the Gauge Element.

The working fluid volumes of both the elastomer and piston units are given in **Table 1**. In a later section, it will be shown how a smaller working fluid volume might limit the maximum pressure response of a given system.

Table 1. Gauge Protector Working Fluid Volumes.

Vendor	Diaphragm Type	Piston Type
A	75.0 mL	63.8 mL
B	70.0 mL	115.0 mL
C	------	276.0 mL

Pressure Loss: Diaphragm

As pressure was applied in discrete increments to the process side of a gauge protector, the volume of working fluid discharged to atmospheric pressure was recorded. **Figure 5** shows the cumulative volume of fluid expelled (mL) for a given value of applied process pressure (psig). The procedure was like inflating a balloon, where the pressure inside must be greater than the surrounding atmospheric pressure. A pressure differential accompanies the expansion (stretching) of the diaphragm. At any stage of distention, the differential pressure (psi) across the diaphragm was the same as the gauge pressure (psig), as plotted in Figure 5. These tests indicate that process pressures will always be greater than remote pressures (providing they exceed the LDB limit). The difference depends upon the amount of diaphragm expansion. Figure 5 shows that, when this expansion is near its maximum, process pressures could be as much as 95 psi higher than the pressures transmitted to a remote gauge—regardless of the process pressure. Likewise the UDB limit of the system is reached at this maximum extension.

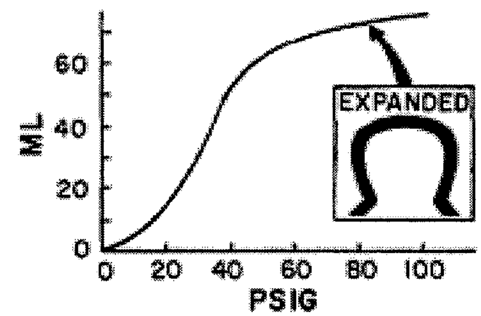

Figure 5: Pressure Required to Expand a Typical Gauge Protector Diaphram vs. Fluid Volume Expelled from the Gauge Protector Reservoir.

Pressure Loss: Piston

Frictional losses for piston-type gauge protectors were found to be negligible. For all three units studied, pressure increases in the range of 5 to 10 psi were required on the process side of a static piston before it moved and a subsequent pressure change was sensed downstream. These same increases were observed at all levels of downstream pressure. Once a moving piston had returned to a rest state, approximately 3 to 5 psi remained as a pressure differential or frictional pressure loss across the piston.

Effects of System Precharge

A common field practice is to pump additional oil into a gauge protector while its process side is at atmospheric pressure. This precharge pressure becomes the LDB limit. All process pressures lower than the precharge value will not be sensed. In some cases, this threshold can be as high as 150 to 200 psig, sufficient to obscure shut-in pressures from kicking formations that have small pressure differentials over that of the wellbore fluid hydrostatic pressure. Some positive attributes of system precharge in a diaphragm unit are that it offsets some of the initial hose expansion and prevents air from entering the fluid link by maintaining a positive pressure inside the hose or fluid link. The working fluid volume increases, and the diaphragm collapses. The increase in working fluid volume associated with precharge pressure for a particular diaphragm-type protector is shown in **Figure 6**. Precharge of a piston-type unit provides all the attributes associated with a precharged diaphragm-type, except it provides no increase in the working fluid volume.

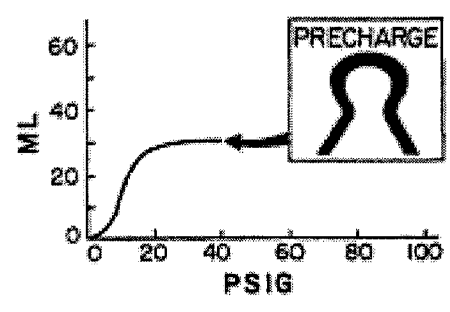

Figure 6: Precharge Pressure Required to Collapse a Typical Gauge Protector Diaphram vs. Fluid Volume Increase in the Gauge Protector Reservoir.

HYDRAULIC HOSE

To quantify the ballooning or expansion of the hose, pressure versus volume data were collected for a 1/4 inch by 50 foot, 10,000 psig rated hose filled with instrument oil. The hose was exercised (pressurized to its maximum working pressure) several times in order to season it, so as to obtain reproducible data. It was found that the "green," or new, hose required more fluid addition to realize a given pressure, as opposed to the seasoned hose. During the study, it was noted that the expansion characteristic of the hose reverted back to the green state when not used for a few weeks. However, with limited use, the hose again returned to a seasoned state. Composite compressibility values for the oil and hose, based upon numerous pressure versus volume tests, are given in **Figure 7**. Note that the data are presented as working fluid demands in terms of mL/ft (of hose) versus internal pressure. This scaling, in mL/ft, will accommodate any particular length of hose.

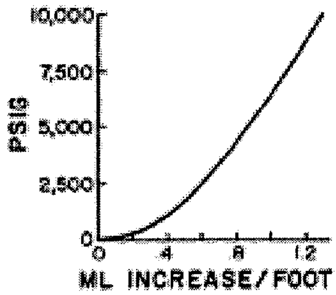

Figure 7: Oil volume demands of a typical hydraulic hose link (free of air) as a function of internal pressure.

STAINLESS STEEL TUBING

To minimize fluid consumption by hose expansion, the flexible hydraulic hose may be replaced by steel tubing. (Though superior, this practice is seldom used in the field because flexible hose proves more practical for mobile drilling rigs.) One-eighth inch stainless steel tubing was tested in an attempt to generate a composite compressibility factor as was done for the hose. However, an injection pressure approaching 10,000 psig was required to realize a working fluid demand of sufficient volume for accurate measurement. Consequently, linear behavior for this factor was assumed. As a constant, the composite compressibility factor was determined to be 0.000032 (mL/psi)/ft of tubing. This approximation was justified solely by the fact that, for normal rig situations, the total working fluid demand of the steel tubing would not be significant even as pressures approach 10,000 psig.

TRAPPED AIR

Free air in the fluid link will not cause errors so long as process pressures are within the responsive range of the system. Being very compressible, however, it could markedly increase the demand for instrument oil in the link. This, in turn, might reduce drastically the UDB limit of the system. Air is often trapped in a system as the gauge protector and hose are filled with oil. Leaking and "breathing" connections (although not recommended for use in the field) are commonly used with quick-disconnect fittings and provide avenues for addition of air to the system.

While not measured in the laboratory model, the effect of trapped air can be predicted precisely using the Real Gas Law:

$$V_2 = V_1 \frac{P_1 T_2 Z_2}{P_2 T_1 Z_1} \tag{3.1}$$

where V1 and V2 represent the air volumes at initial and final conditions respectively; likewise T1 and T2 are the absolute temperatures; P1 and P2 are the absolute pressures; and Z1 and Z2 are the compressibility factors for air. The working fluid demand resulting from compression of the air is given by the difference, (V1 - V2). The compressibility factors may be taken as equal, with the introduction of little error. Furthermore, the additional volume of oil required to compress the air is essentially the initial volume of trapped air at atmospheric pressure. For example, with the fluid link at a pressure of only 200 psig, the trapped air would be reduced to about 7 percent of its original volume. At 500 psig, it would be reduced to only 3 percent.

PRESSURE GAUGE

Working fluid requirements for both pressure transducer and Bourdon tube gauges were determined. Fluid volumes required to drive transducer-type instruments to full scale were essentially zero. Compressibility of the single-coil, Bourdon tube gauge also proved to be minimal. Prior to testing, the tube element was removed from the gauge and purged of air. Pressurization tests defined the compressibility profile that is shown in **Figure 8**. Note that at 10,000 psig only about 1.0 mL of oil was required to extend the gauge full scale, which can be considered negligible. Gauge response or calibration errors were not considered in this study since each gauge appears unique, with accuracy varying by gauge. Gauges are usually recalibrated periodically by certified vendors.

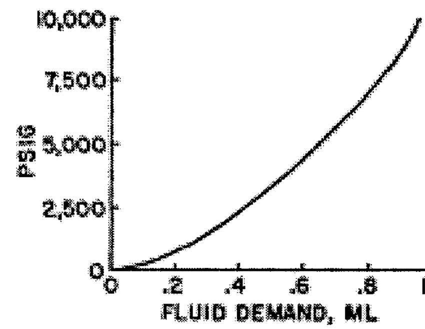

Figure 8: Oil volume required to activate a typical 0 – 10,000 psig, single coil, Bourdon tube gauge.

TEMPERATURE

The effects of temperature on the instrument oil and also on the complete system were studied. The entire gauge protector, hose, and Bourdon gauge system were immersed in a thermostatically controlled water bath. While the pressure source was maintained at 21 °C, the system's temperature was varied from 4 °C to 50 °C. No significant pressure measurement errors were observed due to system exposure to these reasonable temperature excursions, even when pressuring the system to its full-scale limit of 10,000 psig. However, the metered fluid volume required to obtain a common pressure response was not constant during these tests.

Subsequent thermal expansion tests on the instrument oil alone showed its isobaric thermal expansion coefficient, β_o, was a weak function of temperature, namely

$$\beta_o = \frac{1}{1225+T} \tag{3.2}$$

where T is the temperature in degrees Celsius. To predict oil volume changes as a function of temperature change, the instrument oil's temperature-dependent expansion coefficient must be integrated over the temperature range of interest. The volume change for this particular instrument oil may be calculated using the following equation:

$$V_2 = V_1\left[\frac{1225+T_2}{1225+T_1}\right] \quad (3.3)$$

where V1 and T1 represent original conditions and V2 and T2 the final conditions.

Although the oil expands or shrinks with changes in temperature, no errors would be incurred in a soft system, i.e., a system whose gauge protector diaphragm (or piston) was free to move. However, expansion or shrinkage of the oil could affect the LDB and UDB response limits of a system.

System Evaluation Procedure Illustrated

The following example will illustrate the procedures used to determine a gauge reading correction factor and the maximum pressure response limit of a particular system configuration. Consider a properly charged 10,000 psig rated system, consisting of a diaphragm-type protector with a 75 mL reservoir, 50 feet of 1/4-inch hose, and a Bourdon gauge. The initial and final conditions for the example are given in **Table 2.**

Table 2. Conditions for Example Problem.

Property	Initial Conditions	Final Conditions
Temperature (°C) :	35	27
Indicated Pressure (psig):	0	2000
Trapped Air (mL):	15	
Hose Volume (mL):	= (0.7854 d^2 L) = 483	
Total Oil Volume (mL):	V_{hose}-V_{air}+V_{resv} = (483 - 15 + 75) = 543	

The solution requires that the fluid demands of both the hose and gauge be determined. Since there was a temperature reduction, a shrinkage of the instrument oil is expected, which can be treated as an additional demand for working fluid. Compression of the trapped air is yet another demand for working fluid. Summation of all demands for working fluid gives the volume to be expelled from the gauge protector. Figure 5 is then used to determine the pressure loss incurred in expanding the diaphragm while expelling the needed fluid. This value will be the gauge correction factor.

Solution: *Gauge Correction Factor*

	Fluid Demand	Reference
Hose:	26.7 mL	Fig. 7
Gauge:	0.4 mL	Fig. 8
Oil Shrinkage:	3.5 mL	Eq. (3)
Compressed Air:	14.9 mL	Eq. (1)
Total:	45.5 mL	
Gauge Correction:	**35 psi**	Fig. 5
Process Pressure:	2035 psig	

In the example cited here, this 35-psi additive correction or reading error would only represent a 1.7% reading error.

To determine the maximum pressure response, first, the fluid shrinkage and compressed air volumes, as calculated earlier, will have to be replaced by a portion of the original reservoir working fluid. Next, assume all the remaining working fluid will be expelled into the hose. Calculate the fluid volume expelled in mL/ft of hose. Figure 2 can then be used to determine the resulting pressure inside the hose, which would be the maximum pressure response limit of the system.

Solution: *System Maximum Pressure Response Limit*

Initial Reservoir Fluid:	75.0 mL
Shrinkage Loss:	-3.5 mL
Air compression Loss:	-14.9 mL
Remaining Working Fluid:	56.6 mL
Fluid Expelled into Hose:	$1.1\frac{mL}{ft}\left(\frac{56.6}{50}\right)=1.245$ mL
Resulting Hose Pressure (Fig. 7)	7800 psig

Notice that while this system was equipped with a 10,000 psig gauge, process pressures in excess of 7800 psig could not be indicated.

As an extension of the previous example, suppose the system contained an additional 50 feet of hose. Using the same logic as before, a maximum pressure response limit of approximately 2000 psig would result. This restriction would be a very significant limitation and if not recognized would pose a real threat to the safety of personnel and equipment alike.

Validation of Findings and Results

Validating the findings and results of this study consisted of comparing predicted process pressures with the actual pressures applied by the mercury pump. Tests were designed to predict process pressures based on working fluid changes within the system. The procedure was as follows: (1) apply pressure to the process side of the gauge protector; (2) measure the amount of fluid expelled from the protector by means of the metering pump supplying the pressure; (3) convert the displaced fluid to mL/ft by dividing by the length of the hose; (4) use the mL/ft value and Figure 7 to determine the predicted internal pressure of the hose; (5) determine a gauge correction factor from Figure 5; (6) predict the process pressure by adding the gauge correction factor to the predicted hose pressure; and (7) compare this predicted process pressure to the applied process pressure.

Five tests were conducted with different combinations of process pressure, precharge pressure and hose length. The system was purged of air prior to each test and the temperature held constant during all tests. For simplicity, the working fluid demand to activate the gauge element was considered negligible. The results of these tests are given in **Table 3**. Note that the percentage error for the predicted process pressure as compared to the actual process pressure was minimal for the first four tests, two of which included system precharge. Of special importance was the result of the fifth test. The UDB limit was predicted to be extremely low, due to the excessive hose length. When tested, 5000 psig was applied to the process pressure side of the gauge protector. The applied pressure was not observed on the system gauge, but instead, the observed pressure was essentially that predicted for the UDB limit.

Table 3. Comparison of Predicted to Applied Process Pressures.

		Process Pressures		
System Precharge (psig)	Hose Length (ft)	Applied Pressure (psig)	Predicted Pressure (psig)	Prediction Error (%)
0	50	3000	3050	1.7
0	50	8000	8050	0.6
50	50	5500	5500	------
50	50	7000	6900	1.4
0	100	5000	3750	N/A

Conclusions

The conclusions drawn from the results of Phase 1 testing are as follows:

1. Given a properly charged hydraulic pressure measurement system, errors inherent in remote measurements of drillpipe, kill line, and casing pressures are not significant, whether measured electronically or with a pressure gauge.
2. Significant errors can occur in a remote pressure measurement system given the following conditions exist:
   a) an excessive precharge pressure, resulting in an elevated minimum response pressure, (LDB), and/or
   b) insufficient working fluid volume, resulting in a reduced maximum pressure response limit, (UDB).
3. Hose length, trapped air and instrument oil leakage significantly reduced the working fluid available for pressure transmission and will greatly reduce the maximum pressure that can be read.
4. Electronic gauges that eliminate the need for gauge protectors by allowing the sensing strain gauge to be placed in contact with the drilling fluid can provide a significant safety advantage and are recommended for general use, especially when using an automated well control systems.

Chapter

4

Computer-Assisted Deep Water Well Control System

The prototype computer-assisted well control system was found to allow more accurate control of bottom-hole pressure and allowed the choke operator to better observe the overall progress of a kick circulation. A tenfold reduction in BHP variance can be achieved through computer-assisted well control for deep water operations.

This chapter deals with the development and testing of the computer-assisted well control system for deep ocean environments. This work is based on the fact that reliable data can be obtained electronically whether the sensors are directly connected to the pressure sources or connected to the existing rig analog pressure gauge systems (as described in Section 2). Discussed in this section are the methodology and the results obtained from the development of the computer-assisted deep water well control system. Five phases were required for this research: 1) installation of the electronic data input system; 2) alteration of the test well facility; 3) development of the electronic data collection software for slow circulation rate data; 4) development of software to generate a hard copy of the well kill program (kill sheet) for a given kick scenario; and 5) the design of the computer-assisted deep water well control system. Subsection 3.1 contains the methodology to complete each of these phases, with Phases 1 and 2 being self explanatory and the last three to be discussed further in the testing and results portions of this section (Subsections 3.2 and 3.3).

The research test system is described in terms of the LSU test well facility and the computer system used to complete this research. Discussion of the results of this research phase is broken down into three parts: 1) the computer-assisted determination of slow circulation rate data; 2) the computer-generated well kill plan or kill sheet; and 3) the computer-assisted deep water well control system. These are developed and discussed separately.

Methodology

The development of the computer-assisted system was completed in five phases as mentioned above, with the methodology for completing each phase being detailed in the following subsections.

Electronic Data Input

Real-time data inputs were provided by electronic sensors that use a 4-20 milliamp (mA) current loop signal for analog transmission of system pressures (bottom hole, choke or casing, drillpipe or pump, etc.), choke position, pump stroke rate, and mud pit fluid levels. Sensors providing milliamp output signals were chosen to ensure reliable data, i.e., the signals would not be affected or degenerated by signal transmission line length or radio frequency (RF) interference. Considerable potential for RF signal interference is present at the rig site, especially given that the sensor leads are so long and that they act as signal antennae for various stray RF signals. Additionally, since many rig power sources and converted voltages exist, differential input was selected as the input means to the analog-to-digital (A-D-A) input computer card. This selection minimized the potential errors due to current loop interference, which is very difficult to eliminate in a non-controlled environment when using single-ended inputs. In short, the A-D-A input card converts the linear 4-20 mA input signal to a voltage that is compared to a voltage standard within the card. The final numerical field value is determined by a percentage comparison of the input voltage to the standard voltage, and then multiplied by the full scale range of the field sensor.[4]

The A-D-A card selected for converting the current loop sensor data into direct current voltage (vdc) was an I/O Technologies 12-bit card that has the capacity of processing eight analog inputs and two analog outputs.[5] Twelve-bit resolution is based on a binary system, meaning that the input and output signals were converted into 4,096 discrete voltage increments (e.g., a 15,000 psig only has a 15,000 divided by 4096 incremental resolution or a 3+ psi incremental resolution). To take advantage of higher incremental resolution, the pressure sensor range 0-5000 psig full scale was selected since pressures exceeding this span were not anticipated. Rosemount and Bourne brand instruments with 4-20 mA output capability were made available for use at the LSU test facility.

Well Test Facility Alteration Requirements

Adapting the LSU PERTTL test well facility to meet the needs of this research required several facility alterations. The four sections that follow describe in some detail these alterations.

Pump Throttle and Gear Selector Controls

First, the pneumatic throttle and gear selector control systems of the Halliburton fluid pump had to be modified for electrical control from the test facility control room (approximately 200 feet from the fluid pump). The remote throttle control was integrated with a 4-20 mA current loop control by use of a Moore Product Incorporated electrical to pneumatic converter (4-20 mA to 6-30 psig signal conversion) located at the pump, taking advantage of its already in-place pneumatic throttle control. However, the pump throttle required up to 100 psig to go full throttle, necessitating that the 6-30 psig signal be amplified by a 4:1 Moore Product pressure signal multiplier. One additional throttle modification was required in the control room. The manual throttle had to be converted from a pneumatic controller to a 4-20 mA rheostat-type controller, allowing other training operations to be completed independently of this research.

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[4] For example, let's say that a 0-5000 psig pressure sensor (4-20 mA linear transmission signal, 4 mA being 0 psig and 20 mA being 5000 psig) is in the field and is sending a 12.0 mA signal (one-half of full scale) to the A-D-A card. The card converts the input signal to a 0.5 vdc signal (0-1.0 vdc, linearly representing the 4-20 mA input signal). Then the A-D-A card compares the input 0.5 vdc signal to the 1.0 vdc standard and determines the signal to be one-half of full scale. The A-D-A card then passes the 0.5 scale value to the computer as a 0-1.0 vdc value, and then the computer, via software logic, multiplies the percentage voltage signal by the full-scale range of the field sensor to determine the field pressure being read (i.e., multiplying the 0.5 value times the 5000 psig full scale range, resulting in a field pressure reading of 2500 psig).

[5] The software driving the I/O board was written in the BASIC computer language. Therefore, to maintain compatibility, the data collection and manipulation software for the well control program was also written in the BASIC language.

The pump gear selector was easily converted with a multiple contact rotary switch and four 12 vdc ASCO solenoid valves. Converting the gear selector to electrical was not needed for computer control, but for prompt response (due to the existing long pneumatic lines from the control room to the fluid pump station) when a manual gear selection was made at the initiation of the computer-controlled well kill process.

Precise pump speed control was monitored by the installation of a magnetic pickup near a circular 28-tooth sprocket attached to the drive shaft leading from the triplex pump gear box to the fluid pump itself. Pulse signals from the pickup were then converted (via a frequency to milliamp signal converter) to a 4-20 mA signal for input to the computer. A total of 7.8 revolutions (218 proximity switch electrical pulses) of the sprocket represented one stroke of the pump, permitting precise pump rate determination (a resolution higher than commonly found in the field, but easily installed if desired).

Drilling Choke Selection and Control

Two basic drilling choke designs are used in the field: a fixed position type and a pressure regulating type. Fixed position is the dominant design, but modeling this choke type is difficult because it is very choke and fluid dependent and the flow rate versus pressure drop for varying choke positions varies greatly for multiphase flow conditions that occur during well control operations. Since the use of choke position is for pressure control, the hydraulically controlled SWACO 10K Kick Killer choke (formerly designed and owned by Warren Tool Company) was selected. This choke regulates pressure by hydraulically setting a back pressure on the back side of the floating piston used to control fluid flow through the choke body. **Figure 9** depicts the basic design of this choke. The advantage of this choke over other designs is that the computer can set the hydraulic pressure on the back side of the floating piston; the piston then moves to the balanced pressure point (equal pressures) between hydraulic set point pressure and casing pressure. Therefore, control of the casing pressure is completed by setting a desired set point pressure, not choke position, resulting in a casing pressure equal to the set point pressure.

Manual control of the SWACO 10K Kick Killer choke is accomplished via a pneumatic-over-hydraulic pressure system, with the pneumatic pressure control being a hand adjustable, operator-

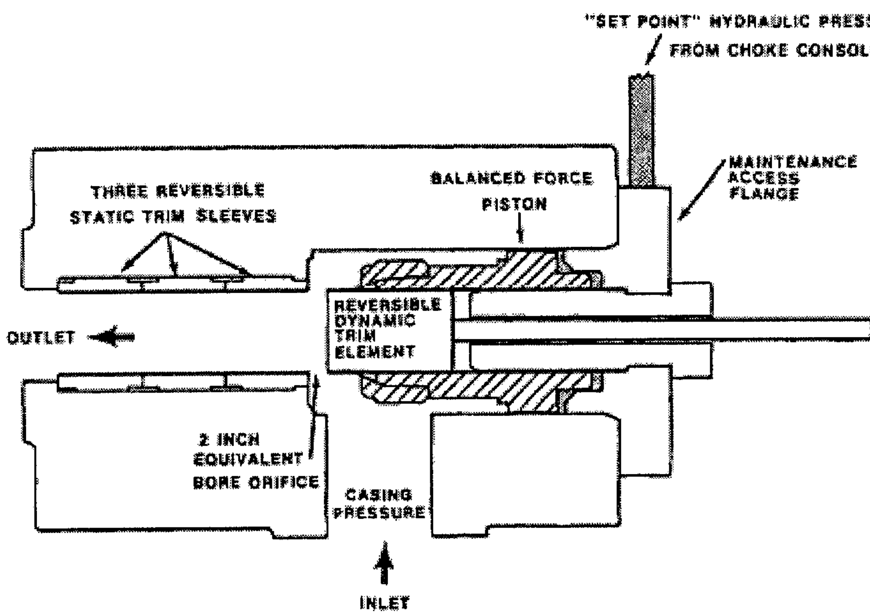

Figure 9: Floating piston drilling choke design.

controlled, 3-15 psig pressure regulator. The subsequently adjusted hydraulic pressure actually dictates an equivalent casing pressure by automatically adjusting the choke element to a position of equivalent, but opposing, pressure. With the use of solenoid valves and electrical to pneumatic converters, the choke was outfitted for computer control as well as manual control. Additionally, a LVDT system with a 4-20 mA output signal was supplied by SWACO and was affixed to the choke stem to provide choke position documentation during the testing of the computer-assisted well control system.

Gas-Out Metering Station

The vent line downstream of the mud-gas separator was retrofitted with a Daniels senior orifice fitting for measuring gas output from the wellbore during a well kill operation. A Daniels Model 2231 gas measuring computer collected the input data from the senior orifice fitting pressure sensors and produced a 4-20 mA gas flow rate signal as an input to the automated well control system.

Reservoir or Gas Kick Simulation System

Three 2000-foot deep cased wellbores were used as storage facilities for high pressure natural gas (up to 4000 psig) for injection into the test well as the kick fluid. The gas was metered into the wellbore via manually controlled pneumatic actuator flow control and gate valves. As a consequence of the test well depth (6000 feet, true vertical depth) and gas deliverability from the kick simulation system, a kick volume of approximately 10 barrels was standardized for the tests. (This volume is representative of an offshore, kicking well that has been detected early and promptly shut-in.) However, given the smaller test well tubular geometry, the 10-barrel kick volume is sufficient to generate a kick length and resulting pressure profile similar to that of a deep water offshore well with a larger volume kick influx. [6]

Slow Circulation Rate Pressures

As stated earlier, choke line friction on startup is one of the more difficult pressure control tasks when beginning a well kill operation. Some choke operators compensate for choke line friction by opening the choke, allowing the casing pressure to drop, and then bringing the fluid pump on line. Once the pump is up to the slow circulation rate (SCR), the choke is then partially closed, adjusting the casing pressure to the original shut-in casing pressure minus the choke line friction. However, this method allows more gas to enter the wellbore while it is in an underbalanced state, worsening the situation. Another method is to drop the casing pressure in four or so incremental steps to offset the increasing choke line friction while bringing the pump on line. This method keeps the well slightly overbalanced when coming up to pump speed, eliminating the underbalanced condition earlier described. This method also minimizes the risk of formation breakdown by not allowing the overbalance to exceed one fourth or so of the choke line frictional value. For this research, the computer was used to capture pump rate and pressure data during the slow circulation rate test period, and the software was written to determine the choke line friction, not as two or three discrete pump rate data points but as curve-fitted data with an established choke line friction equation based on pump or fluid flow rate. This allows the computer to control the reduction of the choke line friction during the startup on a stroke-by-stroke rate increase basis, i.e., integrating the pressure loss over a large number stroke rate intervals instead of just three or four intermediate pump rates. This effects much closer control of the BHP during startups, minimizing the overbalance risk (formation fracture) and the underbalance risk (additional kick fluid influx).

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[6] The LSU test well facility provided an excellent environment for developing and testing the computer-assisted deep water well control system because of this ability to simulate deep ocean kicks.

A program was written in BASIC to dictate that the computer collect pump rate and pressure data, curve fit the data, and store the results in a data file for later access and use. This file is accessed by the computer later when developing the kill sheet and when ramping the pump up to SCR during an actual well kill operation.

Kill Sheet

As a back-up to the automated system, a physical copy of the well kill plan was generated by the computer. Again, the BASIC programming language was used to write code for generating a kill sheet which was formatted like the LSU kill sheet used in the industry training program. The system is capable of generating a kill sheet both for surface and subsurface operations, accommodating both the driller's method and the wait-and-weight method. Additionally, the BASIC program generates a kill sheet that can accommodate two sizes of drillpipe, two sizes of drill collars, a riser, two casing/liner sizes, and an open hole section.

The output product for this phase of the project is a hard copy of a kill sheet. Input for this sheet will be data contained in a morning report data file, the slow circulation rate data file, and manual data input. All input data is screen displayed for on-line correction prior to generation of the kill sheet.

Computer-Assisted Deep Water Well Control System

The computer-assisted system developed has the capability of monitoring the pre-kick wellbore and surface parameters, collecting the post-kick shut-in wellbore pressures, generating the kill sheet described earlier, and then circulating the kick fluid from the wellbore. The system is called computer-assisted and not an automated well control system because the operator identifies the kick, shuts-in the wellbore, and then prompts the computer to collect the shut-in pressures and generate the kill sheet. The operator then initiates the start of the well control program and places the fluid pump and choke in computer control mode while manually selecting the proper gear for the fluid pump.

The system's process control logic includes software designed to instruct the computer on bringing the pump up to speed while adjusting the choke to the proper casing pressure (adjusting for choke line friction) and for switching from casing pressure control to drillpipe pressure control once the SCR has been obtained and stabilized. Once this is completed, the computer holds the drillpipe pressure constant for the remainder of the well kill procedure, if completing a driller's well control method. Software logic is included for the wait-and-weight method, but no runs were made with this technique due to high cost for weighting-up and de-weighting drilling fluids at the well facility.

Closed loop control logic was incorporated to control the fluid pump and the drilling choke. Choke manipulations were made based on pressure differences between the desired control pressure and actual pressure. For the case when a drillpipe pressure schedule is followed, lag time allowances for choke changes were included to avoid making the same corrections multiple times. Additionally, since the pressure transit lag time was so large in the interval from the drilling choke to the drillpipe pressure gauge, a predictor model was added that predicts future changes that will be needed while waiting on the pressure transit to travel the full length of the system. The end result was that each choke change is based on the current pressure change needs, minus those pressure changes that are in transit within the wellbore, plus those pressure changes predicted as being needed prior to the next pressure adjustment.

Development and testing of the computer-assisted system was completed at the PERTTL test well facility using the 6000-foot subsea configured well with 3000 feet of choke line (described in detail later in this section). Natural gas was used as the kick fluid, but only after the system had been tested by circulating out simulated salt water kicks (trapped wellbore pressure). Thirty simulated salt water kicks and 20 natural gas kicks were completed in the development and testing of the system. The end product is a test run documenting the successful circulation of a natural gas kick from the wellbore. These results were then compared with the results of a similar kick manually controlled by an experienced operator.

System and Test Facility Design

The test design consisted of two parts: the test well facility and the computer/process control system. The test well facility, **Figure 10**, consisted of the fluid pump system, the test well, the drilling choke and manifold system, the gas injection/reservoir simulation system, and the mud-gas separator system. All high pressured piping, wellhead equipment, and choke manifold had API 5000 ratings, meaning that the system components are rated to a working pressure of 5000 psig and a test pressure of 7500 psig. The gas injection system carried approximately 4000 psig gas pressure, sufficient to inject a gas volume of approximately 10 barrels at a depth of 6000 feet inside the test well, while providing significant shut-in surface pressures (up to 1000 psig).

LSU's Well # 1 (a subsea research and training well) shown in **Figure 11** was designed to model deep water operations. It was used in the research and testing phase of this effort. This well has been used extensively in the development and testing of concepts for deep water operation. The well design included a triple flow tube located at 3000 feet inside the wellbore to emulate deep water subsea operations, two

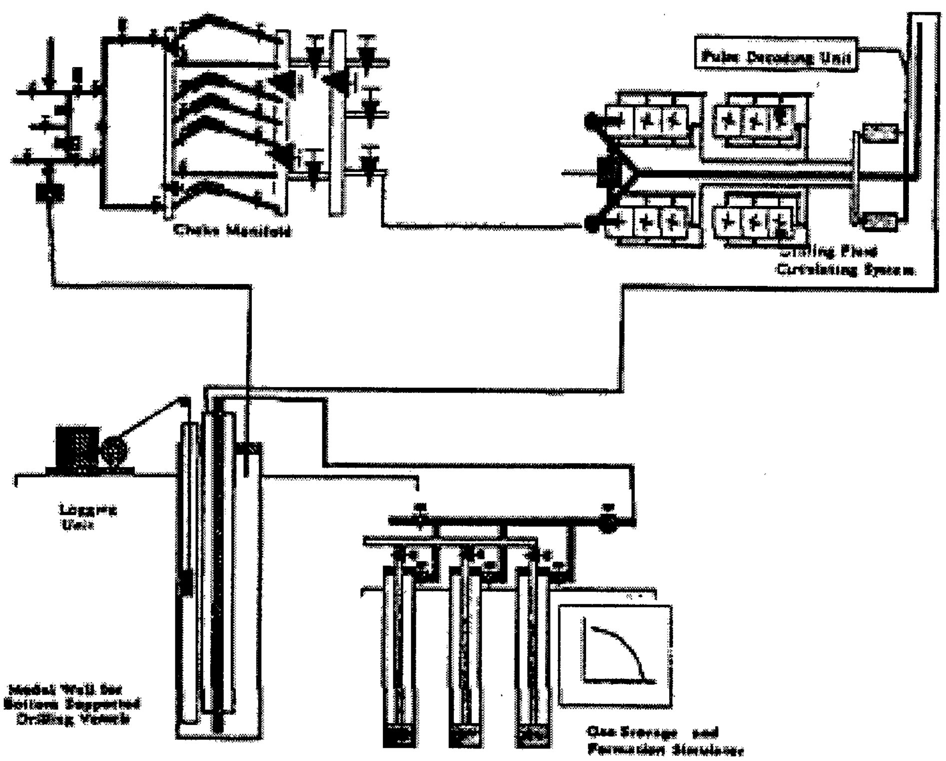

Figure 10: Computer-assisted well control system test well facility.

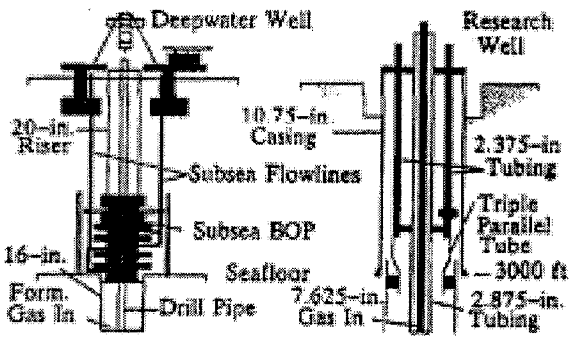

Figure 11: LSU Well No. 1 – -Subsea research and test well.

strings of 2.375-inch OD tubing extended from the flow tube to the surface, modeling both the choke and kill flow lines, and a subsea wing valve for one flow line was modeled using a Hydril surface-controlled subsurface safety valve. The simulated wing valve allowed experiments and training exercises to be conducted using only one flow line, with the other line being isolated from the system (as is often the case during well control operations for floating drilling vessels). The drillpipe or pump line extended from surface to 6000 feet, and was made of 2.875-inch OD tubing, with 1.315-inch tubing extending inside to a depth of 6100 feet. This concentric tubing was used as a gas injection string that facilitated high pressure natural gas or nitrogen injection at the bottom of the hole, emulating a gas kick or influx on bottom.

The second part of the system was the computer/ process control system. **Figure 12** depicts the components of this system and how it interrelates with the test well facility. The computer sends control signals both to the fluid pump and drilling choke while receiving input data such as casing pressure, drillpipe pressure, choke position, fluid pump speed, etc. A six-pen plotter documents the relevant pressures and choke position.

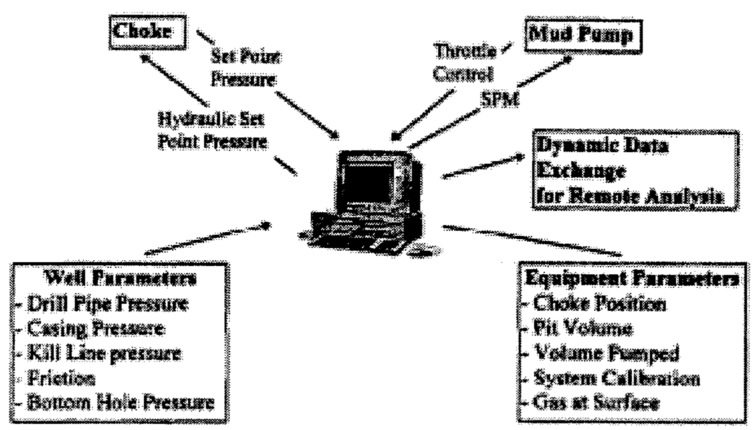

Figure 12: Control schematic for computer-assisted well control systems.

As a safety item, a black box was developed with appropriate switching such that control of the fluid pump and drilling choke can be transferred together or independently from computer control to manual control by toggling a single switch. Also, the milliamp outputs for both the manual and computer pump controllers are to be monitored digitally such that whichever system happens to be off-line can be adjusted to the same milliamp output,[7] but only on standby. Provided that adjustments are made correctly, switching from one system to the other is "bumpless" transfer, i.e., the fluid pump doesn't even

[7] This was accomplished by applying a voltage to a resistive loop created equivalent to that of the pump throttle loop electrical circuit. Milliamp adjustments were manually adjusted by the use of a rheostat. Transfer of control was completed by toggling a switch, transferring the manually controlled (or vice versa for the computer controlled circuit) current from the simulated throttle circuit to the actual throttle circuit.

detect the transfer of control. This type transfer was also developed for the drilling choke pneumatic control system.

Test Results

The results obtained for this phase of the research are broken into or described as three separate components: 1) the computer-assisted determination of slow circulation rate data; 2) the computer-generated well kill plan or kill sheet; and 3) the computer-assisted deep water well control system. Each is discussed below.

Computer-Assisted Slow Circulation Rate Data

As an alternate means to collecting choke line frictional data manually, the data can now be collected by computer and curve fitted, providing unlimited flow rate versus frictional data combinations via equations that are readily accessible by computer. **Table 4** depicts manually collected SCR data[8] that is typical of today's technology. The "Choke Line Friction" data is determined by circulating down the drillstring and up the choke line and through the fully opened bypass on the choke manifold and then subtracting from this value the pump pressure observed when circulating down the drillstring and up the riser. This method assumes no friction in the riser. There are other methods for determining choke line friction, but fully detailing these methods is not needed for this discussion. However for the example described in Table 4, note should be made that the fluid pump strokes per minute (SPM) rates given in the first column actually represent fluid flow rates. Had the data been given in terms of fluid flow rate in lieu of SPM (i.e., bbl/min rather than SPM, which is pump dependent), then the data would not be dependent on pumping equipment. However, the SPM data plots the same as fluid flow rate and is generally more readily accessible. One must keep in mind that this method is very rate dependent, i.e., the rates given in the second and third columns must be exact or the calculated choke line friction will be in error. The only significance of the SPM rates chosen for the SCR data is that they should be representative of potential rates to be used in the event of a well killing operation (usually about 1/2 of the normal circulating rate and typically falling in the 3 to 4 bbl/min flow rate range).

Table 4. Typical SCR Pressure Loss Data for a Subsea Operation.

Circulation Rate (spm)	Pump Pressure Through Riser (psig)	Pump Pressure Through Choke Line (psig)	Choke Line Friction (psi)
30	180	210	30
40	300	350	50
50	450	525	75

The new system developed collects Slow Circulation Rate (SCR) data electronically. The relationship between flow rate and friction loss for non-Newtonian drilling fluids in the turbulent flow

[8] This data was collected while circulating a water based bentonite drilling fluid through LSU Well Number 1 located at PERTTL.

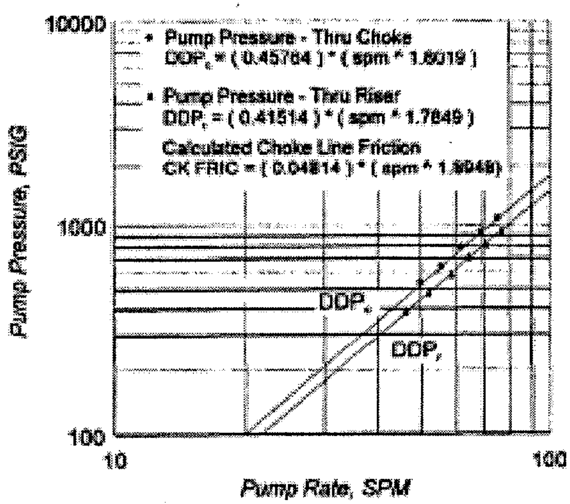

Figure 13: Plot of frictional pressure losses.

regime is known to be exponential in nature. This allows the computer-assisted system to take advantage of the fact that the SCR versus pump pressure data should plot linearly on log-log paper or that each flow path's frictional rate data can be fitted to an equation of the form:

$$p = cq^m \tag{4.1}$$

where:

p = pump pressure, psig
q = fluid flow rate, spm
m = slope of rate vs. pump pressure line
c = constant based on fluid properties and wellbore geometry.

A computer program has been written in the BASIC software language that allows the rig crew to interactively collect the SCR data electronically and in a form useable by the computer-assisted well control system developed. In lieu of making the data collection fully automated, a decision was made to permit the driller, the one normally responsible for manually controlling the fluid pump, to bring the pump up to the varying SCRs and collect the pump rate and pressure data electronically by toggling an interrupt key (set up as one of the F keys). Once the pump rate and pump pressure have stabilized for a given fluid flow rate, the driller enters the data by striking the designated function key, at which time the computer polls the SPM data input and the pump pressure sensors and enters these values as a set of data points.

One advantage of the data being collected in this manner is that the data is typically more precise than if taken manually by visual observations, especially for pump pressure since these values are typically in the less accurate lower 10% of full-scale range of the hydraulic pressure gauge. Once three or so pressure data points are taken for each flow path, a second programmed F key, F2, is toggled, and the computer automatically calculates an exponential curve-fit equation for each flow path, as well as one for the choke line friction itself. The computer then outputs to the printer 1) a hard copy of the tabulated data, 2) the log-log plotted data, and 3) the associated equations, while storing this data in a data file (FRICT2.DAT) for use later in the development of a well control kill sheet and the computer-assisted well kill procedure. **Figure 13** shows a typical output for this system.

In summary, the output products for the computer-assisted frictional data program are as follows:

1. a tabulated rate versus pump pressure data (includes flowing through the riser, flowing through the choke line and manifold bypass, and the actual choke line friction data);
2. a log-log plot of pump rate versus pump pressure data;
3. exponential equations, derived form the frictional data collected, for describing the rate versus pump pressure relationships for flowing down the drillstring and up the riser, for flowing down the drillstring and up the choke line and out the manifold bypass, and for the choke line friction itself; and
4. an electronic data file containing the SCR frictional equation data.

The benefits that can be derived from a SCR data collection system of this type are:

1. the pump pressure data collected is more precise than visually collected analog gauge pressure data;
2. the electronically generated frictional equation is not rate dependent from one flow path to the other (i.e., the pump rates do not have to be equal for each flow path when taking the frictional data), reducing the time necessary to collect the data and resulting in a small savings in rig time;
3. SCR pressure errors are eliminated that are oftentimes introduced by the rig personnel who oftentimes call a stroke rate within one or two strokes of the earlier collected data the same in order to speed the process and save rig time;
4. theoretically, an infinite number of SCRs can be chosen and the frictional pressures known as a consequence of the frictional or pressure loss equations (not limiting the crew to the two or three rates based on the earlier chosen SCR rates, as is typically the current case);[9]
5. having an infinite number of friction rate data sets (pump rate and pump pressure) permits the choke line friction to be incrementally subtracted from the post-kick shut-in casing pressure upon start-up of the well kill procedure, eliminating the over-pressuring of downhole formations during the initiation of well control operations; and,
6. passing the electronically generated frictional equations into a data file permits incorporating the more precise data into the computer-assisted well control system that has been developed for this work.

Computer-Generated Well Kill Plan

A BASIC computer program has been written to generate a hard copy kill sheet for use when manually controlling a well kill operation or for use in following the progress of a computer-assisted well kill. This program is capable of generating a well kill program for vertical or near vertical wellbores both for surface and subsurface operations, and will accommodate both the driller's and the wait-and-weight constant bottom hole pressure well control methods. For subsurface operations, the program will accommodate a well configuration that includes a riser, a choke line, an air gap, a casing, a liner, a length of open hole, two drillpipe sizes, and two drill collar sizes. For surface operations, all the aforementioned will be accommodated except that the prompts for the riser and air gap parameters are deleted. The output of the kill sheet is automatically altered based on the type of stack configuration and the downhole configuration. All references to equipment not included in a given well scenario are deleted, i.e., all form headings and the itemized data numbering scheme are specific to the well configuration.

All well configuration and hole depth data is imported from a data file (DRLRPT1.DAT) containing the driller's morning report information. Included in the data file are the true vertical and measured depths of the wellbore, the casing and liner setting depths and pertinent data (outside diameter, inside diameter, weight per foot, grade burst rating, and the collapse rating), the drillpipe and drill collar lengths and pertinent data (outside diameter, inside diameter, and weight per foot), the bit size, drilling fluid weight, and SCR frictional data. However, prior to importing the previously mentioned data, the computer will prompt the operator to enter the kick data (true vertical and measured depth at the time of the kick, shut-in drillpipe pressure, shut-in casing pressure, and the pit gain.

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[9] There are other means of determining frictional pressure losses at rates other than at the SCRs used for data collection, but the average person in the field is unaware of these techniques. For example, the data can be manually plotted on a log-log form and new data can be interpolated, but this is not as precise as an equation describing the plot.

Once all the data have been imported and entered, they are displayed on the screen to be validated by the operator. After all the data have been reviewed and corrected as needed, the kill sheet is generated.

Computer-Assisted Well Control System

A computer-assisted deep water well control computer program has been written which brings together 1) the frictional data collected, curve fitted and stored in the data file called FRICT2.DAT; 2) the morning report data stored in DRLRPT1.DAT; and 3) the post kick shut-in data (shut-in drillpipe, casing, and kill line pressures and the kick volume information). Though our emphasis is on deep water wells, the program discussed in this section will accommodate shallow water or land configurations, as well as the deep water sites. As discussed earlier, deep water locations are the focus for this effort due to the rig crew's inability to maintain proper control of surface and downhole pressures consistently during a deep water well control event. As earlier identified, this is a consequence of the long choke line and its associated choke line friction, plus the extended pressure update or lag times required for the process control parameter, the drillpipe pressure. Both phenomena, excessive choke line friction and choke change pressure transient lag times, make the crucial objective of maintaining constant BHP a difficult task to meet for most rig personnel.

Before describing the results of this research program, a base line for comparing the results to current operational technology will be presented. Using LSU's Well #1 (described earlier), a gas kick of approximately 10 barrels in volume was taken at a depth of 6000 feet true vertical depth (TVD) with shut-in pressures of approximately 775 and 700 psig for the casing and drillpipe pressures, respectively. Pertinent data (drillpipe pressure, casing pressure, pump speed, choke position, BHP, and gas out rate) were collected during the well kill operation. The well kill operation was completed by industry rig personnel (who were attending LSU's well control school) operating the drilling choke and fluid pump manually, which is the current practice in the field. The results of this well control event are shown in Figures 14 and 15.

As can be seen in **Figure 14**, well control operations began by bringing the pump on line at the two-minute mark, and the crew had considerable difficulty in properly handling the choke line friction. Pressures fluctuated approximately 500 psig while attempts were made to reduce the casing pressure by the appropriate amount of choke line friction when establishing the initial drillpipe circulation pressure. A pressure variance of this magnitude could have fractured the formation at the shoe or caused an additional kick influx to occur had this been a critical well. Further analysis of Figure 14 indicates that control of BHP throughout the well kill operation was maintained within ±200 psi of the desired value. Again, this could be critical for deep water wells.

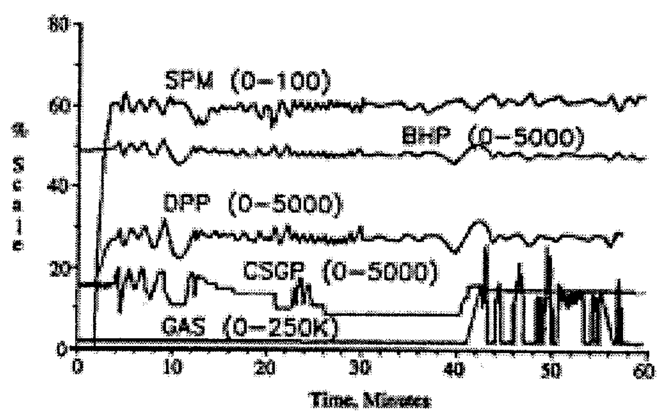


Figure 14: Manually-controlled subsea well kill procedure.

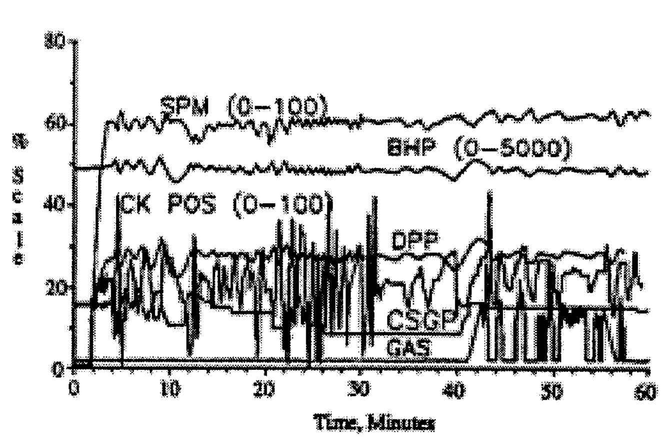


Figure 15: Manually-controlled subsea well kill procedure with choke position shown

Figure 15 gives the reader a good sense of how the rig crew handled controlling the long choke line and pressure time lags associated with choke changes. This figure has the choke position superimposed over the data of Figure 14. As can be seen, the choke operator overcorrected with the choke and made too many large changes. This response is typically seen at the LSU industry well control school. Operators who do not use the choke often typically do not make choke changes sufficiently small enough to avoid overcorrecting. As a consequence of these large choke position changes, the pressures change more tan intended and when the operator sees this, an over correction is made in the opposite direction. Instructors at the training facility have observed that, in extreme cases, the choke operator oscillates from fully closed to fully open on choke position. In the field this would be known as an extreme case of the "windshield wiper effect," i.e., opening the choke while the pressures are rising, then reversing to close the choke when pressures start to fall.

The BASIC language computer program has process control logic for controlling the fluid pump and the drilling choke. The logic for both operations is based on closed loop technology[10] with the fluid pump being a proportional [11] controller and the choke being a proportional-plus-derivative[12] controller.

The results achieved by the development of the computer-assisted well control system can best be demonstrated by allowing the computer to control a well kill operation similar to the previously-taken 10 barrel kick in the LSU Well #1. The results of this run are given in **Figure 16**. As can be seen, the pump start-up procedure was accomplished almost without fluctuation in bottom hole pressure (BHP). Start-up, i.e., control using the casing pressure as the control variable, began at between three and four minutes and continued up to about seven minutes. At this point, control was transferred from the casing pressure as

[10] "Closed loop" means that the process controller gets feedback or input from the device or operation being controlled and future control responses are based on the input data.

[11] Proportional controllers operate by outputting responses that are proportional to the size of the variance in the control variable(s) (e.g., large variances in the process variable are addressed by proportionally larger response changes to the control or output variable).

[12] Derivative controllers base the control response on the rate of change of the process variable. In controlling the drilling choke, the response is based on the current change needed based on the immediate variance between the control variable and the set point or the desired value (proportional response), plus derivative response, where the control pressure is being modeled with a curve fit and future anticipated responses predicted (based on rate change) prior to the next control iteration.

the control variable to the drillpipe pressure, at which time a small BHP pressure fluctuation was experienced until the drillpipe pressure had sufficient data to predict the needed changes.

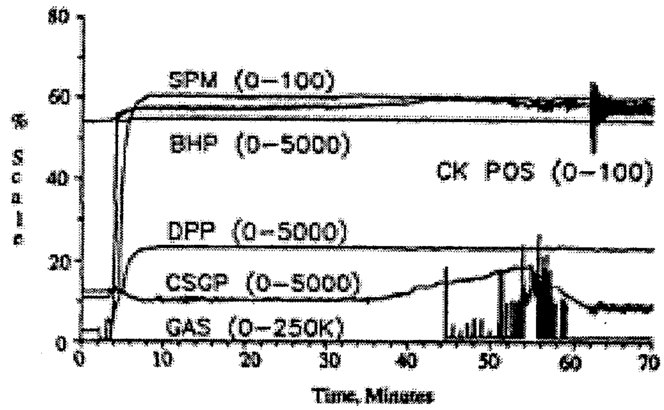


Figure 16: Computer-assited subsea well kill example, Driller's Method.

Because this is a driller's method example, once up to SCR, the drillpipe was to be held constant throughout the well kill operation. Note especially that at the time of rapid choke line gas expansion, beginning at about the 36-minute mark (noted by the rapid rise in casing pressure), the automated drilling choke process control model did not overcorrect. Control changes for the choke were made often (approximately every three to five seconds), but the choke orifice size changes were very small (shown in Figure 16), contrary to the manually controlled well kill earlier discussed. As gas began rapidly expanding up the choke line, the choke was opened more rapidly, as can be seen, and as soon as the larger gas volumes started exiting through the choke (at about the 51-minute mark), the choke was closed at a more rapid pace.

Ringing was observed in the choke position, beginning at the 61-minute mark, after the kick had been circulated from the well. Ringing was thought to occur for the choke design used for very small fluid system compressibilities. This phenomenon made appropriate choke movements much more difficult to predict. However, these instantaneous choke changes and associated pressure pulses were not so excessive that effective control of the drillpipe pressure or bottom-hole pressure was compromised. Examining the BHP shows that all these changes were attenuated out of the system before reaching the bottom of the hole.

The overall result of the well control event can be observed in the plot of bottom hole pressure. As can be seen, the overall bottom hole pressure was controlled to within approximately 20 psi, a tenfold improvement over the manual well control event. Also, it can be seen that BHP control was effectively maintained throughout the well control event.

In summary, a system has been completed and tested that provides computer-assisted deep water well control. Findings of this research include the following:

1. errors in bottom hole pressure and casing seat pressure of 200 psig are common during well control operations with manually controlled choke and pump operations, and
2. equipment and technology exists that will adequately perform the choke control function of a computer-assisted well control system.

The major attributes of the computer-assisted deep water well control system are that it:

1. provides computer control of both the fluid pump and drilling choke functions;
2. monitors all pertinent well control parameters, maintaining continual control with real time data;

3. provides routine (within 5 seconds) choke and pump adjustments, allowing the computer to make minor adjustments;
4. provides enhanced pressure control over manually controlled well control start-ups by incorporating previously developed frictional equations for determining appropriate casing or choke pressure schedules;
5. provides closed loop proportional pump control process control logic;
6. provides closed loop proportional plus derivative process control logic for drillpipe pressure control, making current pressure adjustment decisions based on short term historical data plus the rate change (derivative) of the control parameter;
7. provides well control event digital and hard copy historical data records;
8. can be easily adapted to incorporate newly developed technology; and
9. does not required data inputs with which the rig personnel are not already familiar.

Major benefits to be derived from the computer-assisted deep water well control system are that:

1. the tedious tasks of fluid pump and drilling choke control are managed by the computer, freeing the rig personnel to concentrate on the overall well control process;
2. start-up procedures are effectively managed, subtracting out choke line friction based on the earlier determined frictional equations;
3. surface and casing seat pressures are minimized due to effective control of BHP (±20 psi for the LSU test well set-up), resulting in reduced potential for underground and surface blowouts;
4. overall wellbore circulation time is reduced due to the reduced potential for secondary kicks; and
5. automation of the well control process eliminates the potential for communication errors between the pump and choke operators.

Conclusions

The overall conclusions for this phase of the research determined that as much as a tenfold reduction in BHP variance may be achieved through computer-assisted well control for deep water operations. This has been demonstrated to be achievable at LSU's PERTTL with the use of LSU Well #1. Increased BHP control, as demonstrated, equates into reduced potential for secondary kicks, underground flow, underground blowouts and surface blowouts. These benefits are achievable with existing equipment and technology. The system as developed included computer-assisted systems for collection and modeling slow circulation rate frictional data, generating a well kill plan or kill sheet for either surface or subsurface operations (wait-and weight or driller's method), and providing process control for the entire well kill operation.

Chapter 5

Automated Detection of Underground Blowouts

Experience has shown that dangerous situations develop when an underground blowout goes undetected during the initial phases of a well control operation. Automated underground blowout detection criteria were added to the prototype well control system.

Tremendous financial losses can be incurred as a consequence of an underground blowout, the uncontrolled flow of formation fluids from one formation to another, with sometimes no obvious signs at the surface. In fact, underground blowouts may go undetected for long periods of time. Even though the costs of these events are extreme, it should be recognized that other factors could drive the blowout recovery costs even higher. For example, in the event of shallow casing or a shallow hole in the casing and an extended length of open hole, the possibility of cratering exists. Should the well crater, not only are reserves lost, but a surface blowout occurs with possible loss of life, total loss of the rig equipment, and extensive environmental damage.

During drilling, an underground blowout is typically preceded by lost returns. If lost circulation is encountered at the bit, the fluid level in the wellbore will fall, with a corresponding loss of hydrostatic pressure, allowing an upper zone to flow. However, if returns are lost to an upper zone, an increase in mud volume at the surface may be initially seen instead of a mud loss. When an upward migration of kicking fluids occurs within the annulus, this is sometimes accompanied by erratic shut-in pressures. The common belief is that most underground blowouts occur once a kick has been taken and the blowout preventers have been closed. It is this concern that makes computer-assisted well control for deep ocean environments viable. Also it is the reason for extending this research to automated detection of underground blowouts utilizing expert systems (rule-based) logic.

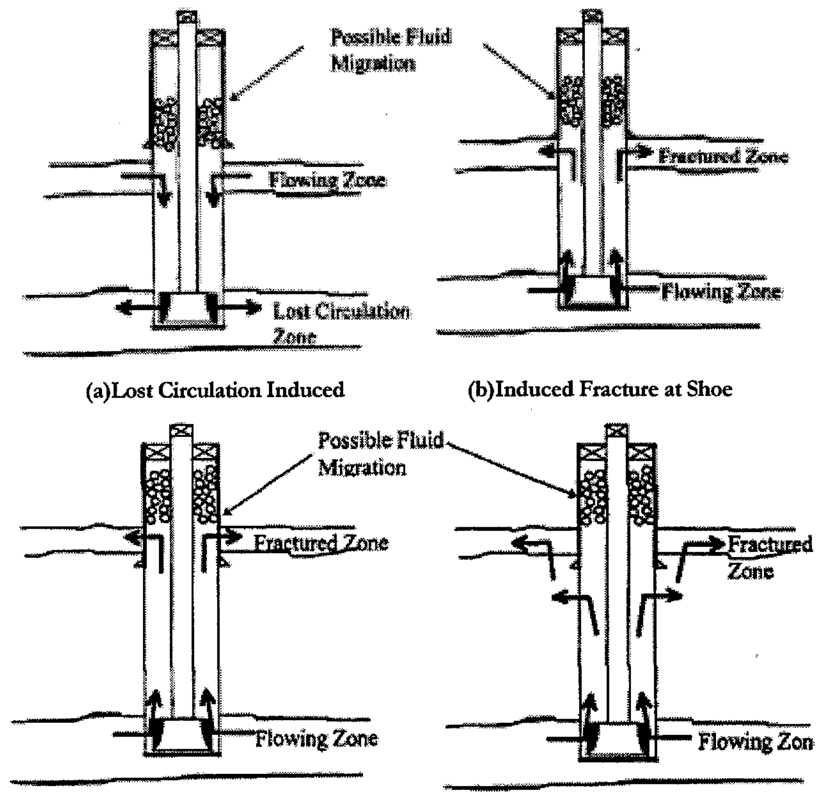
The phase of research covered in this section was completed to demonstrate that real time automated detection of underground blowouts during well kill operations is practical using today's technology. This was accomplished through the integration of enhanced underground blowout analysis software developed for use as an integral part of the computer-assisted deep water well control system. LSU Well #1 was reworked to emulate lost circulation conditions, permitting the enhanced computer-assisted well control system to be tested. As part of this work, the software developed earlier in our research was converted to more current PC technology using National Instrument's LabVIEW ® software and data acquisition system. The software was then altered to include expert systems analysis software to accommodate detection of underground blowouts.

Background: Manifestations of Underground Blowouts

Underground blowouts are more easily corrected when they are diagnosed soon after they occur. Additionally, determining the direction of flow is equally important since this will affect the type of remedial action to be implemented. Early detection will possibly minimize the magnitude of the downhole problem and the potential for getting the drillpipe stuck. The volume and density of the transient influx fluids, as well as which tubulars are involved, are difficult to ascertain. Typically, these unknowns are resolved with temperature (most likely differential temperature), noise, and radioactive tracer surveys.

During drilling, underground blowouts are generally manifested by loss of fluid pressure and insufficient bottom hole pressure at the bit. The lost circulation can be a result of penetrating a subnormally pressured zone, depleted zone, highly fractured zone, unsealed fault plane, and others. Whatever the loss zone type, fluid flow from an upper zone can and will be initiated once the fluid level falls sufficiently if an upper zone has adequate porosity and permeability and is charged with an in-situ fluid capable of movement. This situation has been depicted in **Figure 17a.** When lost circulation is recognized and cross-flow or an underground blowout is suspected, the well is then shut-in and remedial actions planned.

This project demonstrated the practicality of underground blowout detection once normal well kill operations have been initiated. The situation of interest is an underground blowout that is hard to detect based on shut-in conditions alone. In other words, up to the point of bringing the pump on line for a well kill operation, no obvious manifestations of an underground blowout are present. Given the boundaries of this work, onset of an underground blowout is the result of insufficient kick tolerance, resulting in formation fracture and fluid flow from a higher pressured formation downhole. **Figures 17b, 17c,** and **17d** are scenarios common to post-kick underground blowouts.



(a)Lost Circulation Induced

(b)Induced Fracture at Shoe

(c) Induced fracture at hole in casing

(d) Leaky cement with fractured zone

Figure 17: Underground blowout scenarios

During well shut-in, formation fracture at the shoe is a common scenario for underground flow or an underground blowout if the shut-in or circulating casing pressure is too high. However, leaky cement jobs and casing failures all too often cause formation fractures and, consequently, initiate underground blowouts.

Early detection of underground blowouts that flow from deep formations to shallower formations is of considerable concern due to the abnormal charging of the upper zone(s). Under certain conditions, a surface blowout and possible cratering can ensue due to formation fluids channeling to the surface.

Use of Computers in the Detection of Underground Blowouts

The major obstacle to overcome by detecting underground blowouts during well kill operations is inconsistent pressure control during start-up, followed by the continued inability of most choke operators to maintain proper pressure control. These pressure fluctuations mask subtle signs of lost circulation and/or underground blowouts. In fact, lost circulation is often induced during the start-up phase of the well kill process, especially in deep water where there is considerable choke line friction and little kick tolerance. The computer-assisted well control system developed has documented that pressures can be maintained as closely as ±20 psi when using computer-assisted pump and choke control, compared to the ±200 psi routinely seen when experience operators manually control the drilling choke.

Because using computer-assisted pump and choke control results in better surface and downhole pressure control, surface pressure and pit level trends can be tracked more accurately. Therefore, this portion of the project was designed to integrate lost circulation and underground blowout expert system analysis software into the computer-assisted well control system previously developed. Casing seat pressure upon shut-in is calculated compared to the fracture pressure determined from leak-off or pressure integrity tests. Pressure or pit level trend anomalies are searched every second, a schedule not practical for human operators, even if pressures could be properly maintained using manual control. Abnormally low pump pressures after pump start-up as compared to the theoretical pump pressure for the pump speed and choke position present are an important early warning sign. Eventually, the pit level trend should verify the loss of drilling fluid to the formation. Once an anomaly is detected, the computer will alert the operator via a visual and /or audible alarm.

System Design

The software developed earlier for computer-assisted deep water well control has been converted from the BASIC software platform to a PC-based system developed by National Instruments called LabVIEW®. Additionally, a data acquisition and control system developed by National Instruments was installed at LSU's test well facility to interface between the computer control system and the test well. **Figures 18** and **19** are control screens and real time data plots from the newly developed system. **Figure 20** is a sample portion of the code used by LabVIEW® (in the form of an electronics wiring diagram).

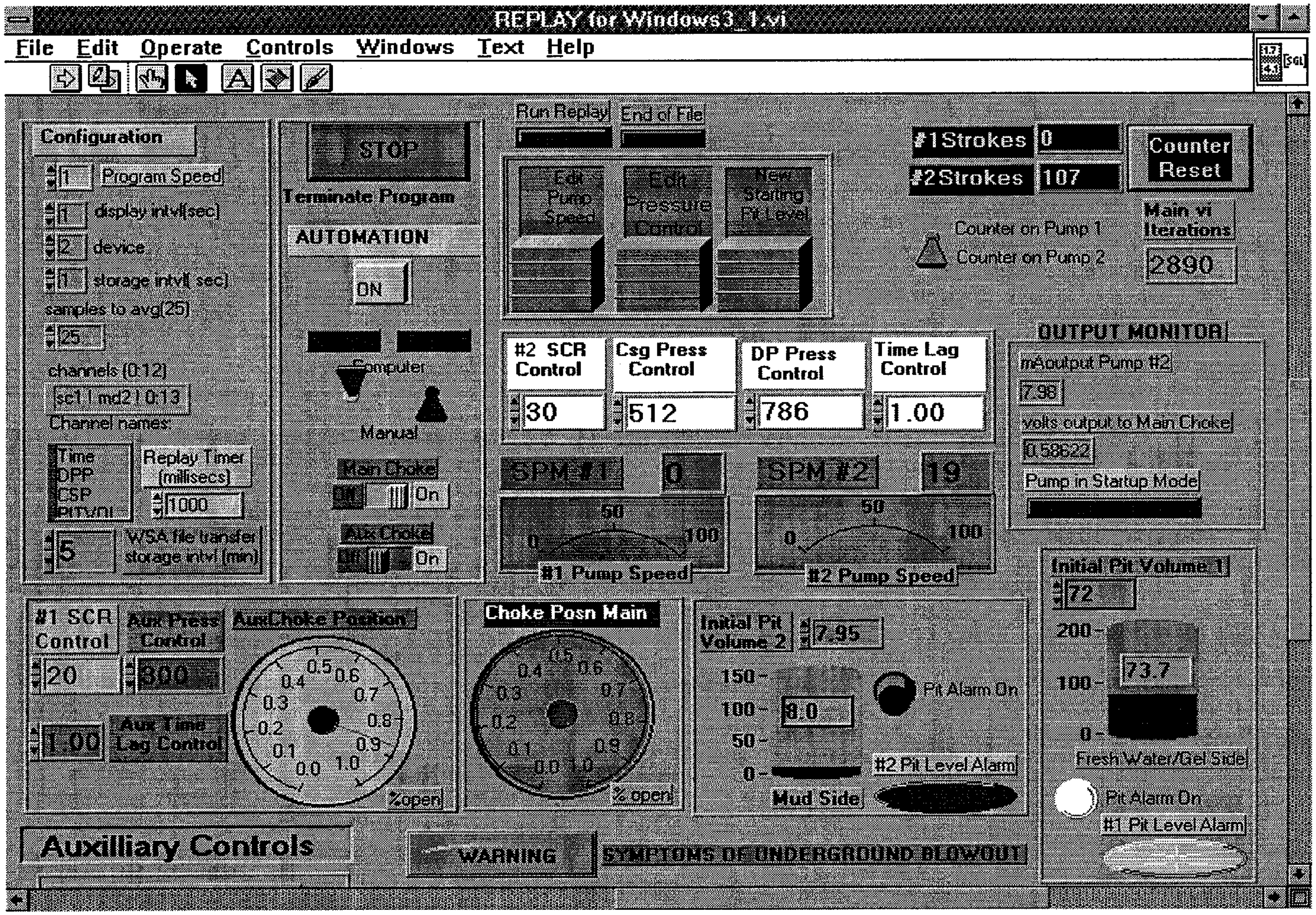


Figure 18: Control panel for automated system.

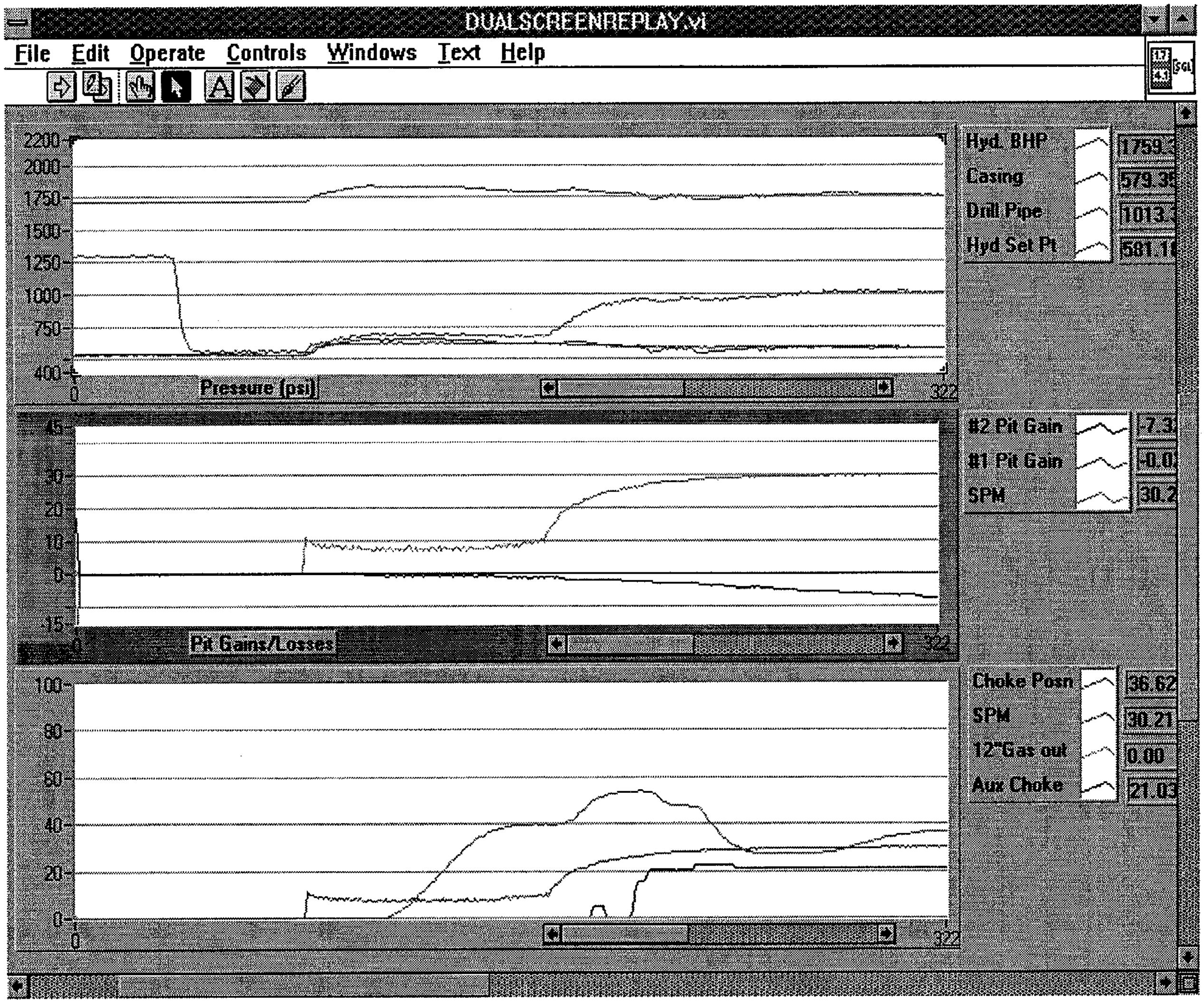


Figure 19: Real time output screen.

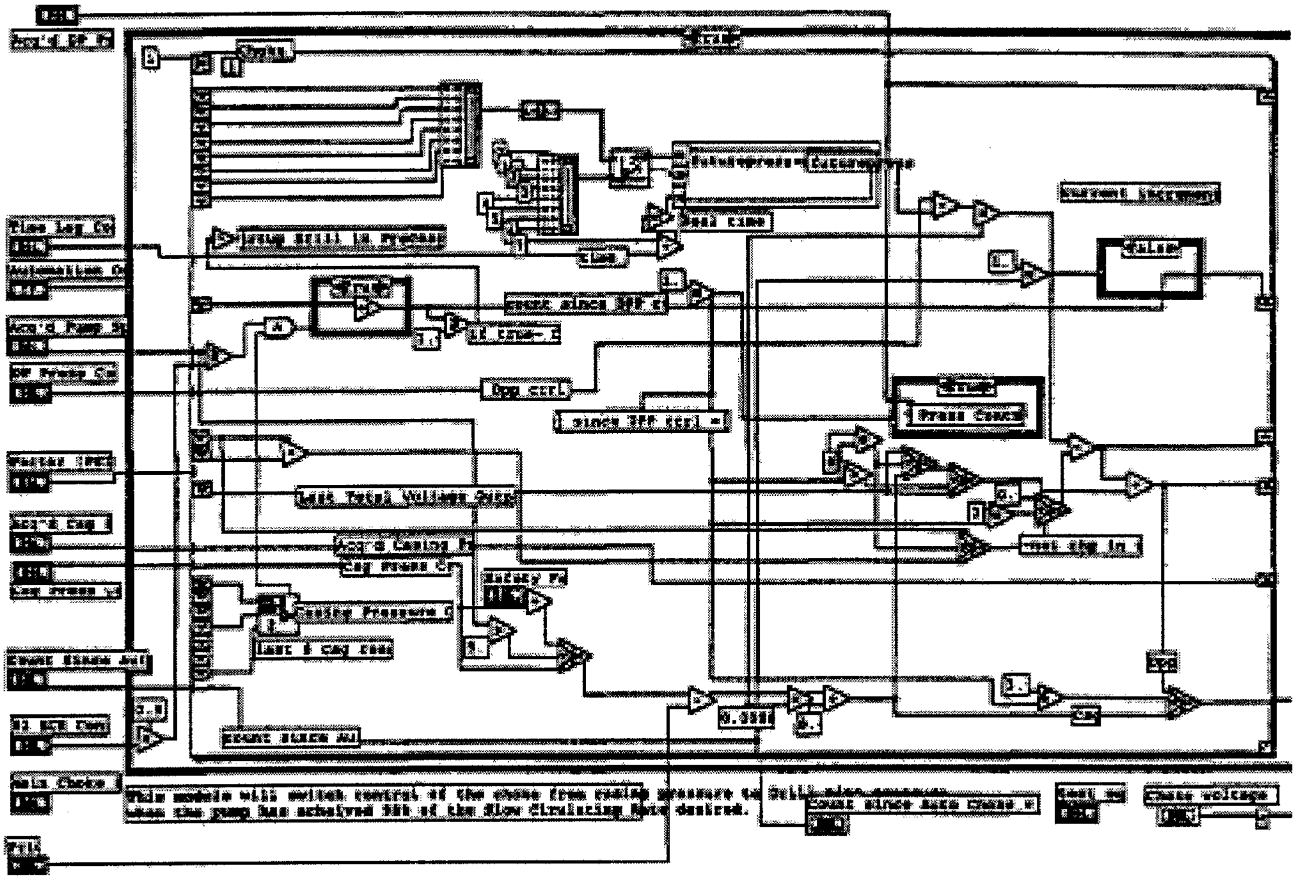


Figure 20: Sample LabVIEW® Code.

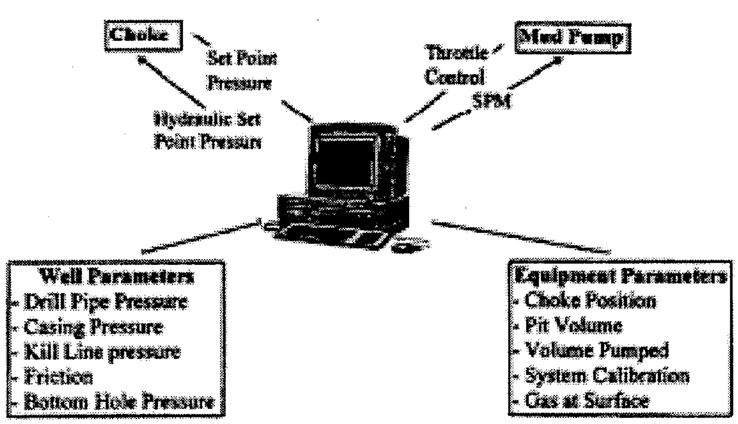


Figure 21: Automated computer system.

The system requires data input of these parameters: drillpipe pressure, casing or choke pressure, kill or monitor line pressure, pump speed, pit level, choke position, choke set point pressure, gas out, and total strokes pumped. Outputs generated by the computerized system include pump speed control, choke set point control, and digital alarms. **Figure 21** depicts the interaction between the computer and the test well facility.

Capabilities designed into the system include:

1. Continual kick detection and well parameters are monitored during drilling operations;
2. Precise choke line friction pressure control corrections are made on start-up (i.e., the choke or casing pressure is reduced by the appropriate choke line friction, based on fluid flow or pump speed, as discussed in the previous chapter);
3. Once circulating at slow pump speed, the pump speed can be altered (increased or decreased) and the system switches automatically to casing pressure control during the speed control transition. The casing pressure is held constant, except to make corrections to facilitate choke line frictional changes resulting from circulation rate changes. Once the new pump speed is established and the casing pressure is stable, the system returns to drillpipe pressure control. For surface or jack-up configurations, the frictional changes are assumed equal to zero. Therefore, the casing pressure is held constant during pump speed changes;
4. A safety factor or over pressure has been added, which is implementable upon start-up to minimize the potential for secondary kicks; (This factor carries over from casing pressure to drillpipe pressure control and can be altered any time during the pump-out cycle.)
5. Digital alarms, both visual and audible, automatically alert the operator to anomalies that may be due to an underground blowout;
6. Control transfer from computer-assisted to manual control is completed by simply toggling a switch;
7. Expert system software logic has been added to detect anomalies described earlier for lost circulation or underground blowout detection; and
8. All are parameters available for dynamic data exchange. (Current data files are effortlessly and routinely dumped in protocol formats (ASCII, string files, etc.) so that various file dependent expert systems can be incorporated into the same computer or shared via a network or modem connection to other computers and personnel. This adds considerable value to the program in that many of the algorithms previously developed (e.g., Well Site Advisor [TRACOR, 1992]) need not be recreated, only incorporated.).

The new software has closed loop systems logic for the pump and choke control. The pump throttle control is proportional in nature, whereas the drillpipe pressure control model has proportional plus derivative control logic. The system fully checks all parameters every second and makes corrections accordingly.

Test Facility

Figure 22 shows the general layout of LSU's test well facility as used in this study. Included in the system are a triplex Halliburton fluid pump (2.9 gal/stroke), precharge centrifugal pump, two 90-barrel mud tanks, two SWACO (previously Warren Tool Company) drilling choke systems, LSU Well #1, natural gas compressor, degassing and flaring equipment, and a data acquisition system. The choke system used is the SWACO 10K Kick Killer, described previously. All flow lines and choke manifolds are API 5000 rated. The formation influx or the kick fluids used during testing included both liquid and natural gas.

Figure 23 depicts LSU Well #1 in use for developing and validating the underground flow and underground blowout detection software. The arrows show the normal flow paths for a subsea or subsurface configuration. The well had to be reworked from the configuration used in the earlier phases of this research due to tubular failures. The true vertical depth of the well is now 2787 feet. The rework afforded LSU the opportunity to design the well so that lost circulation, the precursor to underground blowouts, can be simulated. Lost returns are simulated by taking flow through a second choke (outside the normal flow path) via the outer annulus. Adjusting flow rates from this annulus can give erratic shut-in or flowing pressures, such as those commonly seen in real underground flow scenarios.

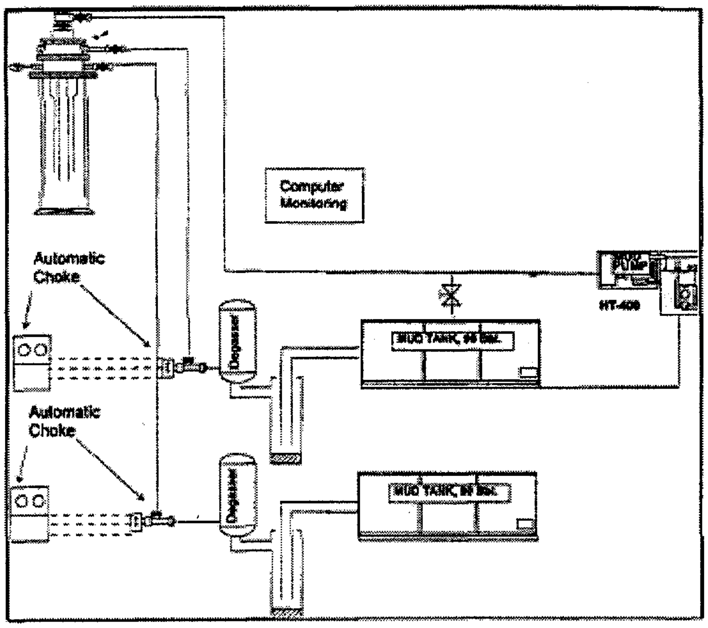


Figure 22: LSU test well facility.

Test Procedure

The test procedure included converting and enhancing the earlier developed computer-assisted deep water well control software. Twenty simulated saltwater kicks were used to validate the software updates prior to initiating gas kick evaluation. A total of 15 natural gas kicks, approximately seven barrels each, were taken. The software following each test run was modified to enhance or fine tune the process control. Appropriate alarms have been added for underground flow detection (i.e., blinking indicator on the screen as well as audible alarms).

The procedure for each test included calibrating the system to ensure that input pressure and control pressures were within acceptable limits (pit level reading ±1/2 barrel, pressure readings ±10 psi, output pressure ± 10 psi, pump rate within 0.5 strokes per minute). The key to detecting underground blowouts is tight control of the automated well kill operation so that anomalies can be discerned. Each time a software change (or group of changes) was made, a simulated salt water kick was taken in the well to validate the effects achieved. Once the software had been converted and validated, software changes were made to key in on underground flow signatures as described earlier, detection being identified to the operator by both visual and audible alarms.

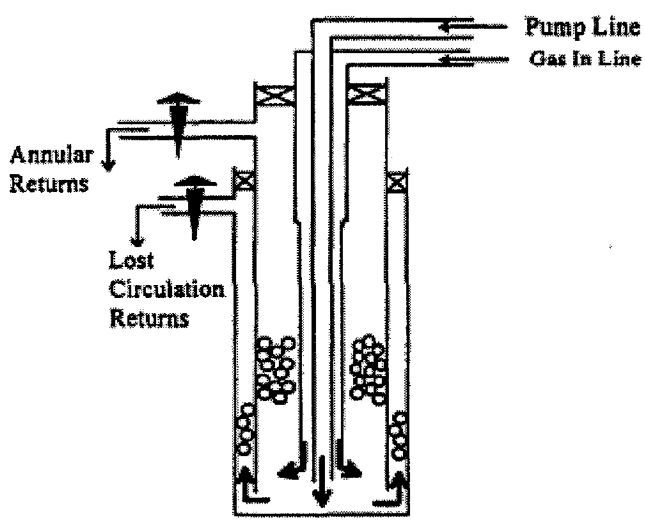


Figure 23: LSU Well No. 1, Subsea configured.

Results

Consistent choke and pump manipulation by the computer during routine automated startups has been achieved with the LabVIEW® software conversion. **Figure 24** is a plot of an actual liquid kick being circulated out of the well. As can be seen, the choke line friction is removed from the shut-in casing pressure on start-up. Note that a 50-psi safety factor was requested and can be seen on the bottom hole pressure plot at pump start-up. Other characteristics of the plot are the parabolic ramp-up of the pump and corresponding drillpipe pressure increase. Note the smooth transition from casing pressure control to drillpipe pressure control once the pump is up to speed at 30 strokes per minute.

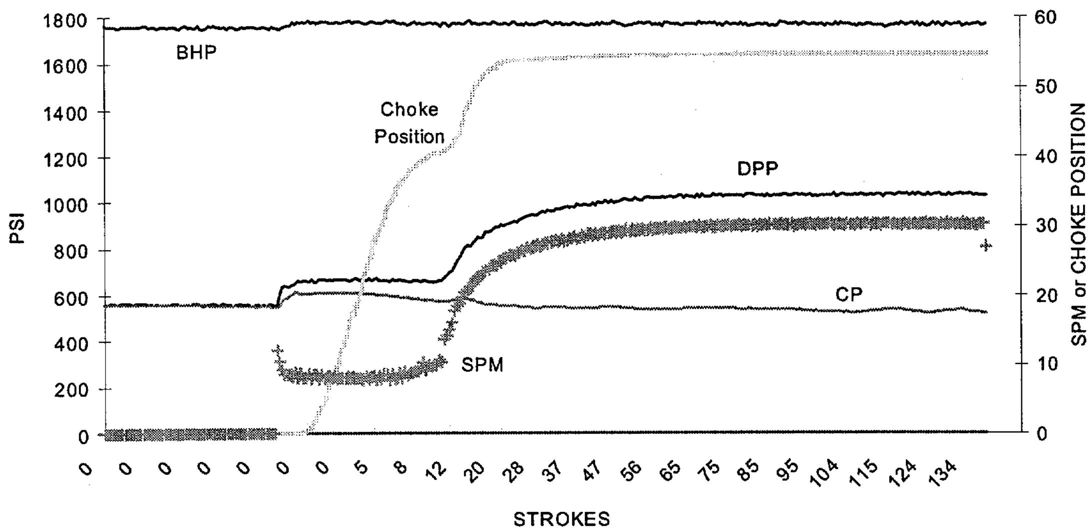


Figure 24: Kick being circulated out of the well.

Figure 25 shows another run with simulated anomalies or lost returns at 243 and 283 strokes. During the run, another choke was opened, allowing fluid to flow via the outside annulus, thereby

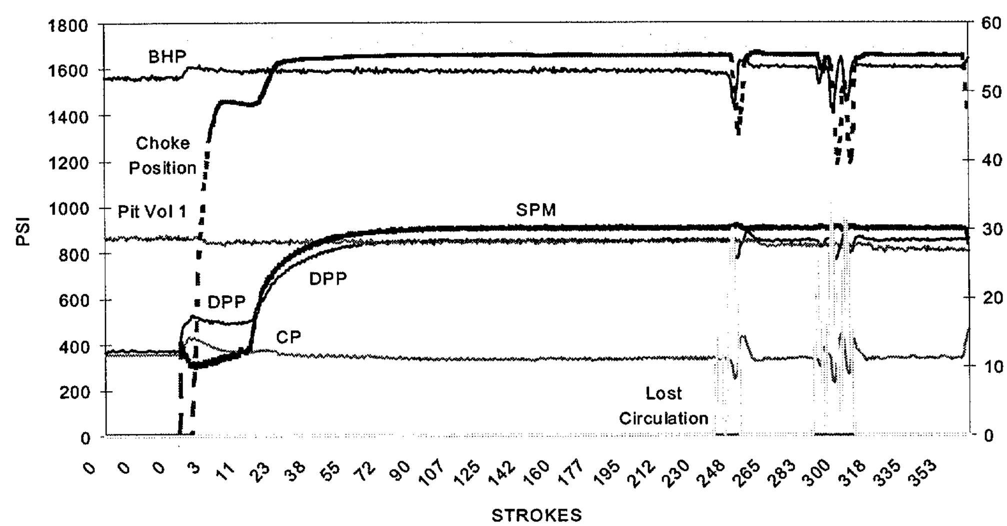


Figure 25: Lost returns.

simulating lost returns. As can be seen, the pressure drops felt throughout the system were significant and sudden. Note should be made that the system immediately recognized the pressure drops, responding with immediate choke corrections and recovered control. These fluid losses were interjected intermittently during the run so that the automated system would be taxed when regaining control. For an actual "in-field" lost circulation problem or an underground blowout situation, just closing the choke will not always recover the well. But with the precise control of pressures achieved by the computer-assisted system, abnormal movements of choke position in conjunction with pit level changes are keyed upon for problem recognition.

Finally, **Figure 26** demonstrates a continual lost circulation problem that occurs while circulating out a gas kick. Note the continual pit loss even though gas is expanding as it comes up the wellbore. Also, note the response of the choke in attempting to regain full control of the well. Bottom hole pressure was affected, but not nearly as significantly as would have occurred if left unchecked. Again, the lost circulation alarms were energized, indicating a possible underground blowout, as was simulated in this scenario.

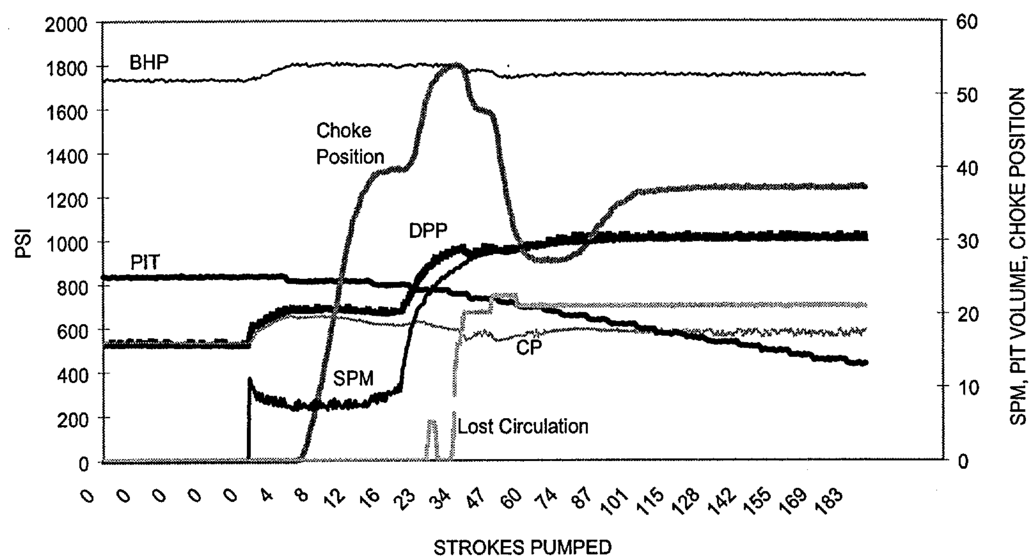


Figure 26: Continual lost circulation.

The results of all tests demonstrated that high-quality pressure control during a well control operation and proper rule-based logic can allow anomalies such as lost circulation or underground blowouts to be detected in real time. Finally, as a consequence of better pressure control with the use of the computer-assisted deep water well control system, other problems can easily be detected with minimal rule-based logic. These would include plugged or washed out nozzle(s), washed out choke, plugged or partially plugged choke, and hole(s) in the drillstring.

Conclusions

1. Precise pressure control for well kill operations is necessary if subtle anomalies or trends are to be quickly detected (e.g., lost circulation, etc.).

2. The prototype computer-assisted well control system demonstrated that such a system could be capable of controlling well pressures so that even subtle, 20 psi, anomalies can be detected.
3. The prototype computer-assisted well control system demonstrated that detection of underground blowouts during well kill operations can be enhanced with automated expert systems logic.
4. Detection of other anomalies such as plugged or washed out nozzles, holes in the drillstring, and plugged or partially plugged chokes can easily be incorporated based on pit level and surface pressure changes. All this is made possible by the precise pressure control obtainable through the use of computer-assisted well control.

Chapter 6

Recommendations

LSU is interested in promoting the commercial development of a system similar to the prototype system demonstrated in this project. Service companies interested in considering such a development project should contact the LSU Petroleum Engineering Department to arrange for a confidential appraisal of the algorithms system developed. One service company is currently undergoing such an appraisal.

Conclusions drawn from each phase of the project are summarized at the end of Chapters 3,4, and 5 and will not be repeated here. The technical feasibility of a computer assisted well control system that could reduce the risk of underground blowouts and more quickly detect underground blowouts when they do occur has been successfully demonstrated. Safety can be increased as a result of computer-assisted well control because of more precise control of bottom-hole and casing seat pressures and because the operators are freed to monitor the overall process rather than controlling tedious operations such as fluid pump and drilling choke control. More precise control of down-hole pressures is important in deepwater locations of the OCS regions because of the reduced fracture resistance of the deepwater sediments to conventional riser drilling operations.

Recommendations

1. The commercial development of a system similar to the prototype system developed in this project is recommended. LSU should take an active role in promoting such development projects.
2. LSU should maintain the computer controlled pump and choke operation interfaces and the required input data sensor system developed in the project in an operational condition to be able to assist an interested vendor in commercial development and testing of similar systems.
3. LSU should make an effort to maintain the working algorithms in a useable code and not become out-of-date as computer operating systems and process control languages continues to advance and change.
4. Dynamic data exchange should be included in future computer-assisted deep water well control system designs to ease inclusion of commercially available analysis software.
5. Rule-based logic should be added to the current software algorithms for detection of plugged or washed out nozzle(s), washed out choke, plugged or partially plugged choke, hole(s) in the drillstring, etc.
6. Digital gauges which can be connected directly to working fluid pressure sources, should be used in commercial systems to eliminate the risk of remote pressure measurement errors that can result due to improperly charged or maintained gauge protector systems.

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